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EPA Program Status Report: Synthetic Fuels from Coal, Including Process Overview with Emphasis on Environmental Considerations

Cameron Engineers, Inc, Denver, Colo.

Prepared for

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EPA PROGRAM STATUS REPORT: SYNTHETIC FUELS FROM COAL

INCLUDING PROCESS OVERVIEW WITH EMPHASIS ON ENVIRONMENTAL CONSIDERATIONS

Interagency
Energy-Environment
Research and Development
Program Report

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16. ABSTRACT

The status of EPA's Synthetic Fuels from Coal Program as of July 1977 is presented. Processes with emphasis on environmental considerations are also described. This program is a part of EPA's interagency energy-related environmental research program directed toward providing the necessary technology for meeting near-term and long-term energy requirements in an environmentally acceptable manner. The objective of the program is to assess the environmental impacts from processes for producing synthetic fuels from coal, and develop appropriate pollution-control technology.

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Air Pollution	Gasification	BI-GAS	Koppers-Totzek	07A	08G
Coal Gasification	High-Btu Gasification	Coalcon	Lurgi Process	07B	10A
Coal Liquefaction	Liquefaction	COED	Slagging/Lurgi Gasifier	07D	14A
Control Technology Development	Low-Btu Gasification	CO_2 Acceptor	Solvent Refined Coal	08D	14B
CTD	Medium-Btu Gasification	Donor Solvent	SRC		
EA	Solid Waste	Fischer-Tropsch	Synthane		
Environmental Assessment	Synthetic Fuels	H-Coal	Synthoil		
Environmental Impacts	Water Pollution	HYGAS	Winkler		

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FOREWORD

This report is both a status report on EPA projects related to synthetic fuels from coal, and an overview of a number of significant processes for coal conversion. Together, they provide under a single editorial umbrella a comprehensive, detailed review of EPA's expanding program in this important area of fossil fuels.

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PART I
EPA PROGRAM STATUS REPORT

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1. INTRODUCTION AND SUMMARY

As domestic supplies of natural gas and oil dwindle, the nation is being forced to seek out alternatives. A significant alternative is coal, and in The National Energy Plan, presented by President Carter on April 29, 1977, an expansion in the Government's coal research and development program is strongly encouraged:

> "Coal will meet the greatest portion of increased U.S. energy needs. A comprehensive coal research and development program is a high priority. The program should focus on meeting environmental requirements more effectively and economically, and should seek to expand the substitution of coal for natural gas and petroleum products."

Included among the highest priorities are programs to develop environmentally sound and economically viable processes for converting coal into gas and oil, or synthetic fuels as they are called. Synthetic fuels are especially important in that they can be used in such urgent areas as transportation and residential heating. A secondary factor simulating interest has been the difficulty of converting oil- and gas-burning power units to coal. A large number of industrial boilers cannot be switched to coal because of design considerations, while plants technically capable of making the change have the economic problem of purchasing unloading, conveying, storage, ash-handling and air-cleaning equipment. A better option may be to replace natural gas and oil with synthetics extracted from coal.

Whatever options are chosen, they must meet energy goals without damaging the environment. As the Energy Plan notes:

> "Attainment and maintenance of the environmental goals set out in the Clean Air Act, the Federal Water Pollution Control Act, and the National Environmental Policy Act are high national priorities. The Administration intends to achieve its energy goals without endangering the public health or degrading the environment."

Processes for extracting gas and oil from coal may produce substances harmful to health and the environment. Present data characterizing the various technologies have been too limited to make judgments as to their acceptability or to set regulatory standards.

As a result, the Environmental Protection Agency (EPA) and the Energy Research and Development Administration (ERDA) have been directed to establish a thorough, ongoing joint effort aimed at parallel ERDA energy development and EPA control of environmental impact. EPA will set up procedures for determining environmental standards, and is to make certain that standards and pollution controls are in effect before the new technologies are ready for commercial use.

EPA's main goal is to see to it that any needed add-on control measures are developed. If in-process technology is required to control pollution, first responsibility for developing it rests with those organizations (government and private) developing the basic conversion process. However, if this responsibility is not met, EPA is required to pursue in-process development in specific areas. EPA has also undertaken the coordination of all governmental research and development efforts for environmental control of synthetic fuel production and use.

Basically, EPA's roles are to assess the environmental impacts from synthetic fuels processes and to determine appropriate pollution control technology. The work involves an assessment of processes already in use and an estimation of which processes in various stages of development are most likely to reach commercial application. Considering the many technologies that are in the experimental state and the technical and economic variables attendant to them, EPA's task is quite complex.

There must be a continual review of the state-of-the-art in synthetic fuels technology. Unfeasible processes must be dropped and new ones added as technical, cost, and pollution factors become evident. For these reasons, the processes described in Part II of this report should in no way be viewed as final. Constant updating will be required, and future reports on synthetic fuels from coal may cover a different selection of processes.

2. PROGRAM BACKGROUND AND OVERVIEW

The production of synthetic fuels from coal is not new. In the early part of the 1800's, street lamps used gas from coal. In this century many American and European cities had "gasworks" that manufactured gas from coal for use in homes and industry. The coal gas used was high in carbon monoxide content and would not be permitted in households today. During World War II a fuel oil suitable for military use was produced from coal in Germany. More recently, coal-to-gas conversion has been performed on a commercial scale in Europe and South Africa. In the U.S., several Wellman-Galusha Gasifiers, manufactured by McDowell-Wellman Engineering Company of Cleveland, Ohio, are serving industrial plants.

EPA's Synthetic Fuels from Coal Program began in 1972. The program was expanded for many reasons: the impetus of the 1973 oil embargo, the resulting increases in the price of petroleum, and the subsequent need to find alternatives to oil. Justification for EPA's increased role comes from the realization that chemicals with adverse, health-related effects might be generated when coal, the primary alternative, has its chemical matrix torn apart during conversion.

To put the problem in perspective, a coal gasification plant producing 250 million standard cubic feet per day of pipeline gas from eastern U.S. bituminous coal will require about 52 million pounds per day of coal input. Assuming 3.5 percent by weight sulfur content in the feed, a typical value for eastern bituminous coal, 1,820,000 pounds of sulfur compounds per day will flow through the plant.

Hundreds of compounds are among the products of reactions involved in the process of converting coal to synthetic fuels. With this in mind, EPA's initial emphasis was on pollutant evaluation and related data collection. Work was also started on more complex environmental assessments and control technology developments (which incorporate economic analyses) and on bench-scale demonstrations. Early accomplishments included:

- Chemical and physical characterization of the pollution potential of over 100 U.S. coals likely to be used for conversion to oil and gas;
- A symposium on the health and environmental effects and control technology of energy use, which provided a status of activities;
- Identification of the pollution potential and evaluation of available pollution control in seven processes for gasification; Koppers-Totzek, Synthane, etc., and three for liquefaction; Char-Oil Energy Development (COED), Solvent Refined Coal (SRC), and H-Coal;
- Analysis of the problems and opportunities of retrofitting industrial processes to use low-Btu synthetic gas;
- Bench-scale demonstration of an effective method for desulfurization of high temperature acidic gases.

Recent efforts have expanded on the work begun earlier. Projects, conducted by private contractors, are now underway in the areas of environmental assessment and control technology development, including pilot, demonstration, and test projects. Funding comes directly from EPA or in some cases from money passed by EPA through ERDA, so-called pass-through funds.

Environmental assessment: All potential pollutants are being identified and characterized. Information generated by sources outside EPA is being collected and assimilated. Each major category within synthetic fuels from coal technology is under study: low-Btu and high-Btu gasification, and liquefaction. Emphasis is on commercial or near commercial processes but also includes just developing processes. Assessment will determine what pollutants can be controlled or disposed of in an environmentally sound manner and the costs of various control or disposal options. Best control practices will be identified and standards of practice manuals published. Research and development needs will be defined, as will siting criteria for synthetic fuel manufacturing plants.

Control technology development: To facilitate efforts the work has been divided into three areas

common to all processes: (1) pretreatment, water, and waste management, (2) converter output streams, and (3) products and by-products. All areas involve the evaluation of control technology for ensuring that effluents meet environmental standards, and, where necessary, the development of controls to meet requirements. The first area is concerned with crushing, grinding, and other treatment necessary before the coal can be converted to oil or gas. It also deals with water and waste streams, not only for pre-treatment, but for conversion and auxiliary steps. The second area is concerned with effluents from the conversion reactor itself, while the third area is to ensure that products and by-products are environmentally sound in their utilization.

One contractor is working in each of the three areas. Contractors use other organizations as necessary, but make themselves the focal point for accomplishing the required work. Studies are being conducted to develop, evaluate, and, where needed, demonstrate control technology for air and water pollution, solid residues, and other environmental problems associated with each of the three phases. Transfer of pollution control technology from petroleum refining and processing, metallurgical coal processing, and coking will be considered. Efforts are being coordinated with other government agencies as well as foreign countries to reduce costs and avoid duplication of efforts.

Pilot, demonstration, and test projects are an extension of environmental assessment and control technology development. Specifically, the characterization of air and water pollution, solid residues, and other environmental problems will be continued through tests on operating units. A selected number of air, water, and solid samples will be comprehensively analyzed and submitted for biological screening tests. Evaluation of the Yugoslavian Lurgi plant will be expanded to whatever extent negotiations, technology, and funds will permit. Work on the Slagging/Lurgi Gasifier and similar units will also be initiated. Emphasis on joint EPA/ERDA testing of low-Btu industrial gasifiers will be continued as appropriate. The bulk of fiscal year (FY) '75-'77 pass-through funds to ERDA ($1.4 million) were for the Grand Forks Energy Research Center, Grand Forks, North Dakota, and the Morgantown Energy Research Center, Morgantown, West Virginia. The former is operating a pilot plant in slagging, fixed-bed gasification, while the latter is running a low-Btu pilot plant (a fixed-bed gasifier similar to the Wellman-Galusha and Lurgi). These and other programs are described with more detail in "Current Program Status."

3. CURRENT PROGRAM STATUS

Each EPA-funded program relates to more than one of the processes described in Part II of this report. The same is true for programs supported by pass-through funds.

In this chapter, each program is summarized. Abbreviated titles used to identify programs at EPA's Industrial Environmental Research Laboratory, Research Triangle Park, North Carolina, are given in parentheses. Goals are presented, as are the latest accomplishments. Processes covered by a program are noted. A pie chart showing overall funding and funding breakdown then follows.

3.1 ENVIRONMENTAL ASSESSMENT (EA)

The Illinois State Geological Survey, Urbana, Illinois, has been characterizing the chemical nature of coal and coal residues (Characterization of Coal and Residues). Current work is an extension of previous studies in which over 100 coals and their geochemical significance were analyzed. Complete chemical, physical, and mineralogical evaluations of slags, ashes, chars, cleaning wastes, and residues are being conducted. These chemical and mineralogical characteristics are being related to chemical solubilities at several pH's and to biological toxicity of aqueous extracts of the solid waste residues. Term of the present contract is from November 1976 to November 1978. Overall progress has involved completing the chemical characterization of eleven coal solid waste samples. Insofar as the research concerns coal that can be used in the production of synthetic fuels, the project affects all processes.

The Energy and Environmental Research Division of the Research Triangle Institute (RTI), Research Triangle Park, North Carolina, is investigating factors and conditions which cause the production of pollutants from synthetic fuel processes (Non-Isothermal Pollutant Identification). Emphasis is on pollutant production, an area that has been generally neglected in other research and development efforts. The five-year project, lasting from November 1976 to October 1981, will touch on areas involving all processes for producing synthetic fuels from coal. The kinetics of pollutant formation is of major concern. Construction of the batch gasifiers and assembly of the sampling and analytical equipment is nearly complete. In the meantime, tar samples from operating synthetic fuels processes are being used to develop methods for organic fractionation to identify specific compounds. Specifications have been written for a computerized data acquisition system to allow testing for the numerous, complex substances formed by coal conversion.

Two separate programs being conducted by the same company involve (1) characterizing and treating wastewater, and (2) reducing the usage of water in coal conversion systems. Water Purification Associates (WPA), Cambridge, Massachusetts, is conducting the related projects, the first of which is an ERDA Program supported by pass-through funds from EPA, and the second of which is financed directly by EPA.

The ERDA project is a paper study in which six sites have been selected for conceptual designs of integrated water treatment plants for coal conversion (Wastewater Characterization Study). The Program, which began in April 1977, will last for 18 months. Specific processes, as yet undetermined, will be studied. Initial work is reviewing phenol removal and recovery.

The second program is a study of water requirements, availability, conservation, and pollution controls for certain coal conversion processes at various sites in three western states (Water Usage in Coal Conversion). The project runs from September 1976 to September 1978. Work is on schedule, with a report being issued. The study describes various processes, such as Lurgi, BI-GAS, SRC, and Synthane, with emphasis related to their water, heating, and cooling requirements for some of the processes, including electrical power generation from coal. Processes that have been addressed by the program are Lurgi, BI-GAS, CO_2 Acceptor, HYGAS, Winkler, Koppers-Totzek, SRC, and H-Coal.

Battelle Columbus Laboratories, Columbus, Ohio, has a program underway related to the removal of contaminants from fuel (Fuel Contaminants, Phase II-Screening Studies of Removal Techniques). The program is examining certain exploratory methods of pollutant removal that have warranted further attention. Term of the contract is from April 1977 to April 1978. This project overlaps with the Fuel Cleaning Program.

The Radian Corporation, Austin, Texas, is evaluating environmental impacts from technology for converting coal into low- and medium-Btu gas (EA, Low-Btu Gasification). The utilization of the resulting gases by combustion processes will also be environmentally analyzed. Technologies covered under the program are several in number, including the Lurgi, Wellman-Galusha, and Koppers-Totzek for processes described in Part II of this report. Collection and interpretation of the existing data base are nearing completion. Preparation for further data acquisition is taking place through test manual preparation, site visits, trial analytical runs, and equipment purchases. A report has been issued on in-situ coal gasification. Environmental assessment methodologies are being developed and evaluated. Term of the contract is from March 1976 to March 1979.

Also part of the effort to assess low-Btu gasification is a cooperative effort between EPA and ERDA. The two agencies are cooperating to evaluate small-sized, individual, environmentally compatible gasifiers in ERDA's Industrial Program which use up to 200 tons of coal per day (ERDA Industrial Gasifiers). The gasifiers will serve as a practical energy source, as a basis for obtaining data to make improvements in technology, and as a source of environmental data. Potential users of the low-Btu gas to be produced include metal treating, processing, and forming plants; brick, lime or ceramic production facilities, and chemical plants.

The ERDA gasifier program began in early 1976. Agreements have been signed by ERDA with:

- ACUREX Aerotherm, to produce fuel for use in a brick kiln at the Glen-Gery Company plant in York, Pennsylvania;
- The University of Minnesota, Minneapolis, to produce boiler fuel for space heating of the Duluth Campus;
- Pike County, Kentucky, to provide boiler fuel for heating and cooling of housing, a fire station, school, shopping center, and fuel for an industrial park near Pikeville.

TRW, Inc., Redondo Beach, California, will assess environmental impacts from technology for converting coal into high-Btu gas (EA, High-Btu Gasification). Term of the contract is from May 1977 to May 1980. Processes to be covered include BI-GAS, Synthane, HYGAS, CO_2 Acceptor, Slagging/Lurgi Gasifier, and others as appropriate. The goal is to determine the environmental degradation that would occur from the operation of commercial installations and to identify control technology required to reduce or eliminate the adverse environmental impact.

Hittman Associates, Columbia, Maryland, is assessing environmental impacts of technologies for converting coal into liquid fuels (EA, Liquefaction). The utilization of these liquid fuels in stationary sources will also be environmentally analyzed. Processes covered by this program include Coalcon, COED, SRC, H-Coal, Donor Solvent, and Fischer-Tropsch. Term of the contract is from July 1976 to July 1979. Collection and interpretation of the existing data base are proceeding. An overview report is being prepared. Site visits have been made to explore further data acquisition potential. Suggestions are under formulation for a test program on the SRC Process at Fort Lewis, Washington. Data acquisition has also been conducted on the SRC combustion tests at Plant Mitchell, Georgia.

United Technologies Research Center, East Hartford, Connecticut, is conducting an analytical study to define the performance and cost of power conversion systems, including those for coal gasification. This contract began in September 1976 and continues until January 1978. Emphasis is on a process similar to BI-GAS, supplying fuel to combined gas turbine and steam cycles. Other gasifiers are examined. High temperature gas cleaning as well as liquid scrubbing techniques are included in the sulfur removal options considered in the work. The final task of the work plan now being addressed is an overview of the environmental effects of these integrated systems.

EPA is involved in a cooperative program with Yugoslavia, which has Lurgi Gasifiers to produce low-Btu gas (Kosovo Gasifier). The program involves sampling and analysis of plant streams to evaluate the potential environmental impact and the environmental control effectiveness of the plant. The multi-year agreement consists of two phases which progress from major pollutant evaluation to trace and minor constituents.

ERDA's Grand Forks Energy Research Center (GFERC), Grand Forks, North Dakota, is operating a pilot plant (P.P.) for slagging, fixed-bed gasification (GFERC Slagging P.P. Gasifier). EPA pass-through funds are involved. Goals of the program include establishment of a data base on characteristics and investigation of processes for treating the effluents. Of the systems described in this report the Slagging/ Lurgi Gasifier most relates to the project. The program began in April 1977 and will run two years.

ERDA's Lawrence Livermore Laboratory (LLL), Livermore, California, is conducting tests with joint funding from EPA pass-through money on what is essentially a new process for in-situ or underground coal gasification (LLL Coal In-Situ). EPA's involvement is through its Industrial Environmental Research Laboratory in Cincinnati, Ohio. The potential environmental advantages of in-situ over surface processes include lower water requirements and lesser land disturbance. Major environmental concerns are possible surface and aquifer water contamination, safety problems and land subsidence problems. The technical feasibility of in-situ gasification has been proven both overseas and at home. The LLL project which began in July 1974 and is expected to continue until 1985, is developing a steam/oxygen, underground process to produce commercially available, medium-Btu gas. Currently, experimentation has been done with air in preparation for testing with steam and oxygen.

3.2 CONTROL TECHNOLOGY DEVELOPMENT (CTD)

Hydrocarbon Research, Inc , Trenton, New Jersey, is working on development and evaluation of technology for controlling pollution from the converter in fuel treatment, processing, and conversion (CTD, Converter Output). All technologies for converting coal to synthetic fuels will be covered. The scope of work includes operations that treat the converter output streams through the point that they either go to by-product recovery operations, product-forming operations, or environmentally sound on-site or off-site disposal. Term of the contract is from January 1977 to January 1980. Work is continuing with evaluations for acid gas cleanup having been completed.

Catalytic, Inc., Philadelphia, Pennsylvania, has a program underway that will result in technology to control pollution from the use of products and by-products created in synthetic fuel processes, including those described in this report (CTD, Products/By-Products). Term of the contract is from September 1976 to September 1979. A draft copy of a report concerning field sampling and analysis has been completed. A preliminary outline of a standards of practice manual for Koppers-Totzek with ammonia and methanol production has been reviewed with EPA.

Pullman Kellogg, Houston, Texas, is conducting a program that will result in the development of systems for treating water and solid waste (CTD, Water/Waste Management). Technology for coal storage, preparation, and feeding is also a part of the program. Term of the contract is from March 1977 to March 1980. A work plan has been submitted and approved by EPA. Data acquisition via literature search and contacts has begun. Wastes and effluents are being categorized for all processes according to type, quantity, and concentration.

North Carolina State University at Raleigh will operate and test a small pilot facility for raw and acid gas cleanup from coal gasification to determine environmental effects (Raw/Acid Gas Cleanup Test Facility). The principal goal will be the evaluation of operations used to clean the raw gasifier product gas and the subsequent operation for acid gas removal. Processes related to this project are BI-GAS, Synthane, CO_2 Acceptor, Lurgi, Slagging/ Lurgi Gasifier, Wellman-Galusha, and HYGAS. Term of the contract is from October 1976 to September 1981. Design of the facility is by ACUREX Corporation, Aerotherm Division, Mountain View, California.

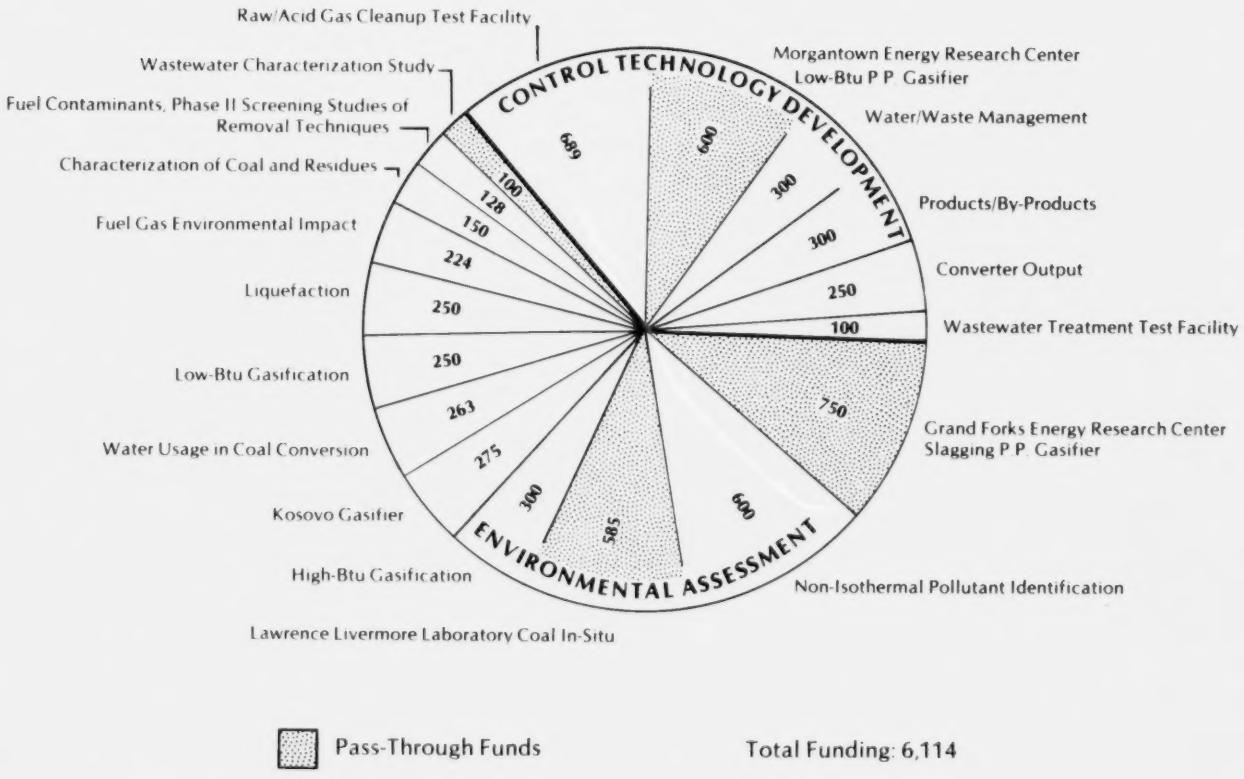
Final review of the design is complete. Construction has EPA approval and site preparation is well underway.

The University of North Carolina at Chapel Hill is assessing the environmental impact of wastewater contaminants from the production of synthetic fuels (Wastewater Treatment Test Facility). Alternative wastewater treatment technologies will also be examined. All processes for producing synthetic fuels from coal relate to this project. Term of the contract is from November 1976 to October 1981. A literature review and survey of coal conversion facilities are complete enough to allow identification of specific contaminants in wastewaters from such facilities. Equipment is being assembled and procedures developed to assess biodegradation of such substances as phenol, cresols, xylenols, and other substituted phenols, pyridines, quinolines, and polynuclear aromatics. Organisms from municipal sewage are to be used as seeds to begin the biodegradation. A parallel effort is underway to use physical/chemical methods to accelerate treatment of biodegradable compounds or to handle compounds which are not biodegradable.

The Morgantown Energy Research Center (MERC), Morgantown, West Virginia, is operating a low-Btu pilot plant gasifier (MERC Low-Btu P.P. Gasifier). The facility, in which pass-through funds are involved, is a fixed-bed gasifier similar to the Wellman-Galusha and Lurgi. The program, which began in April 1977 and will last 18 months, will evaluate effluents from and design control systems for the facility.

Table 1

U.S. EPA ONGOING EFFORTS
IN THE SYNTHETIC FUELS FROM COAL PROGRAM
Fiscal Year 1977 Committed Funds
(in thousands of dollars)



PART II
PROCESS OVERVIEWS

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1. BI-GAS PROCESS

The BI-GAS Process for generation of pipeline gas from coal is currently being developed by Bituminous Coal Research, Inc. (BCR) under contract to ERDA and the American Gas Association (AGA). ERDA is providing two-thirds of the $66 million project funding, AGA one-third. The pilot plant project which is located near Homer City, Pennsylvania, is being managed by the Phillips Petroleum Company.

1.1 PROCESS DESCRIPTION

The BI-GAS Process is a two-stage, high-pressure, oxygen-blown system using pulverized coal, oxygen, and steam in an entrained flow. A diagram of the BI-GAS Process is provided in Figure 1-1.

Raw coal is first pulverized so that approximately 70 percent will pass through 200-mesh. The coal, mixed with water, is fed to a cyclone, where the fine solids are concentrated into a slurry. Coarse underflow from the cyclone is sent to a wet grinding mill for further crushing. The slurry is further concentrated in a thickener and a centrifuge and is then repulped and mixed with flux to provide the desired concentration to be fed to the downstream high-pressure feed system.

A high pressure slurry pump picks up the blended slurry and transports it under pressure to a steam preheater. The hot slurry then contacts the recycle gas in a spray dryer for nearly instantaneous vaporization of the surface moisture. The coal is con-

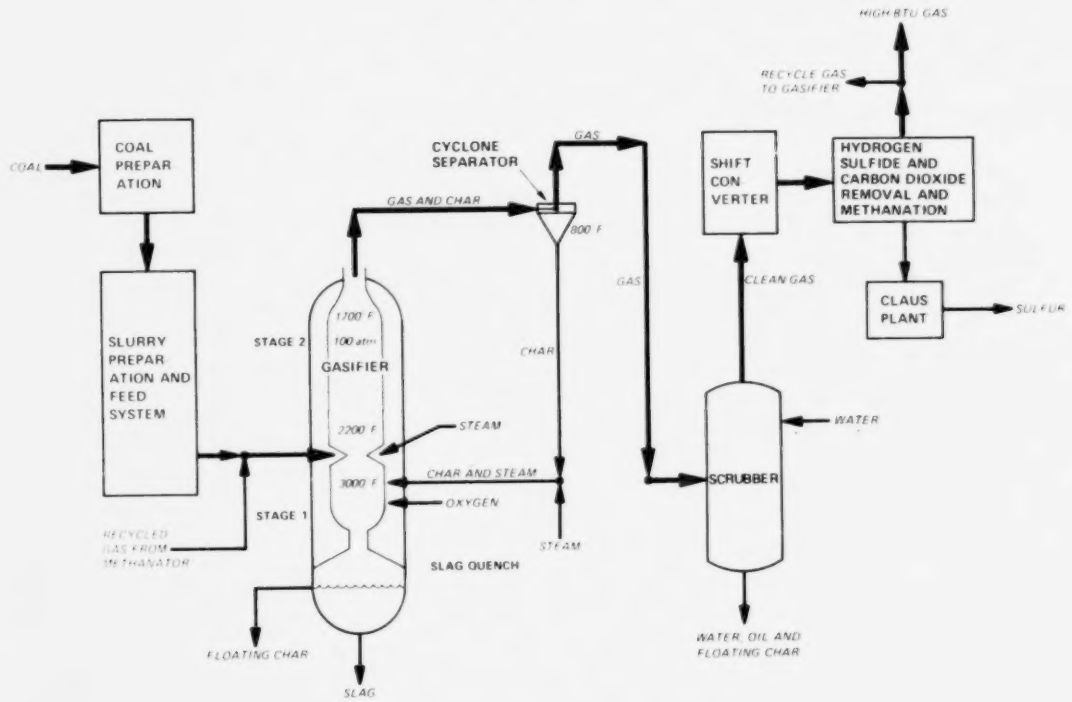

Figure 1-1
BI-GAS PROCESS SCHEMATIC

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veyed to a cyclone at the top of the gasifier vessel by the stream of water vapor and inert recycle gas, as well as additional recycled gas from the methanator. The coal is separated from the hot recycled gas in the cyclone, and the coal flows by gravity to the gasifier.

The coal enters the gasifier through injector nozzles near the throat separating the stages. Steam is introduced through a separate annulus in the injector. The two streams combine at the tip and join the hot synthesis gas rising from Stage 1. A mixing temperature of about 2,200°F is attained rapidly, and the coal is converted to methane, synthesis gas, and char. The raw gas and char rise through Stage 2, the gasifier, at about 1,700°F, and are quenched to 800°F by atomized water prior to separation in a cyclone. The synthesis gas, containing carbon monoxide, carbon dioxide, hydrogen, water, hydrogen sulfide, and methane, passes through a scrubber for additional cooling and cleaning. The clean gas, along with the desired amount of moisture, is sent to a carbon monoxide shift converter to establish the proper ratio of carbon monoxide and hydrogen required in methanation process.

1.2 PROCESS ADVANTAGES

- Gasifier can accept all types of coal;
- Gasifier can be operated with air or oxygen;
- No by-products which require additional processing are produced;
- The absence of tars, oils, naphthas, and phenols in the raw gas simplifies control technology requirements;
- Pressurized operation will be an advantage for gas transmission by pipeline and utilization as a synthesis gas or combined-cycle fuel;
- Cyclone char recycle system permits almost 100 percent carbon conversion;
- Gasifier uses pulverized fuel, which eliminates rejection of fine coal particles.

1.3 PROCESS LIMITATIONS

- Coals with low ash content or high percentage of refractory type ash may require addition of ash fluxing agents;
- Pressurized operation with air has not been demonstrated;
- Gasifier is designed to maximize methane formation in the gasifier which may not be advantageous for all utilization applications;
- The fuel-rich, high-pressure environment in the gasifier will require start-up using pyrophoric materials;
- The low system heat capacity and small reaction zone will necessitate sensitive feed control and automatic, interlocked shutdown control.
- Separation of large amounts of high temperature char from the high-pressure gas stream and metering of the recycled char feed may present operating problems.

1.4 PROJECT HISTORY

This project was initiated in December 1963. BCR's first experiments confirmed the basic assumption that a high yield of methane could be obtained directly from coal by reaction with steam at elevated temperatures and pressures. BCR next conducted continuous flow experiments in an externally heated reactor that used 5 pounds of coal per hour. The data were extrapolated to design a process development unit that would simulate the conditions of Stage 2 of the BI-GAS Process. The unit was internally fired and could process 100 pounds of coal per hour. Experiments were designed to determine the optimum residence time, coal rank, and processing conditions, such as pressure, temperature, and hydrogen partial pressure, that would produce the largest yield of methane. North Dakota lignite, Wyoming subbituminous C coal, and Pennsylvania high volatile A bituminous coal were used in the experiments. During these experiments, BCR found that the physical design of the Stage 2 process development unit influenced methane yield. Therefore, a cold flow model of Stage 1 and the bottom of Stage 2 was developed to investigate methods for improving the flow patterns in Stage 2 and to establish design criteria for the slagging section of the gasifier.

Next, BCR developed the design criteria for a large, fully integrated pilot plant that would process 5 tons of coal per hour and produce 100,000 cubic feet of clean pipeline gas per hour. Responsibility for constructing and operating the $34 million plant was awarded to Stearns-Roger, Inc., on July 11, 1972. The systems management contract was awarded to Phillips Petroleum Company in

November 1974. The BI-GAS Gasifier to be used in the pilot plant was designed and built by Babcock and Wilcox, a Stearns-Roger subcontractor.

Presently, the construction of the pilot plant has been completed and equipment start-up has been initiated. However, various equipment problems have been encountered, and some time will be needed to allow modifications. Pilot plant testing will begin as soon as equipment problems have been rectified.

1.5 ENVIRONMENTAL CONSIDERATIONS

Downstream processing for the BI-GAS Process is identical to that in other second generation, high-Btu processes. The product gas-processing steps are identical to those serving the Synthane plant, and, therefore, the effluents generated are the same. Figure 1-2 illustrates these discharges.

A critical point in the gas processing involves gas clean-up. This step follows shift conversion and removes hydrogen sulfide, carbon dioxide, carbonyl sulfide, and mercaptans from the product stream. There are a number of processes commercially available that assure that product gas will contain as little as 1 ppm hydrogen sulfide. Each developer has decided on various cleanup processes using criteria set up by their engineering team. In most cases, the hydrogen sulfide in the product gas is recovered and sent to a Claus unit for elemental sulfur generation. The carbon dioxide is removed and vented to the atmosphere. This stream is generally 99.5 percent plus carbon dioxide and does not constitute a pollution problem. However, some studies have stated that the carbon dioxide vent may contain as much as 3,400 ppm sulfur and, depending on the acid gas removal process, may contain up to 1 percent combustibles such as ethane and ethylene. These statements are contrary to experiences from operation of these processes in the refining industry. The BI-GAS pilot plant will use a Selexol^{R} unit for acid gas removal and will vent the carbon dioxide directly to the atmosphere.

Coal Preparation and Drying

See the generalized discussion in Appendix B.

Gasification

Effluents to the Air - During pilot operation, there have been no effluents to the air from the gasification section since all the gas streams are contained and processed in downstream equipment. This particular process does not use lock hoppers for coal feeding so that vent gases are not involved. The slurry feed system utilized is closed so that no vapor escape is possible.

Liquid and Solid Effluents - The only solid effluent from the gasifier is the slag formed. The molten slag, about 3,000°F, is quenched in water, a process which fractures the slag sufficiently that an appropriate slurry is formed. In commercial operation, the slurry would be dewatered and the solids sent to the mine site for disposal. The slag is relatively sulfur free and unreactive and poses no particular disposal problem. The water used in the quenching process is collected and reused and is not discharged.

Quench and Dust Removal

Effluents to the Air - The raw gas leaving the gasifier passes through cyclones to recover the entrained char, which is returned to the lower stage of the gasifier. This system is totally contained so that there are no emissions to the air.

Liquid and Solid Effluents - There are no discharges.

Shift Conversion

Effluents to the Air - None are generated.

Liquid and Solid Effluents - Following the shift reactor, the gas is cooled to condense out water. A large amount of sour condensate will be generated. Although this water is recycled, it does contain a varying amount of such compounds as ammonia, cyanides, phenols, etc. These particular materials must either be destroyed in recycling operations or removed from the system. This can be accomplished using various water treatment systems. The solids discharge generated in the unit is the spent catalyst. This material can be easily disposed of in a landfill.

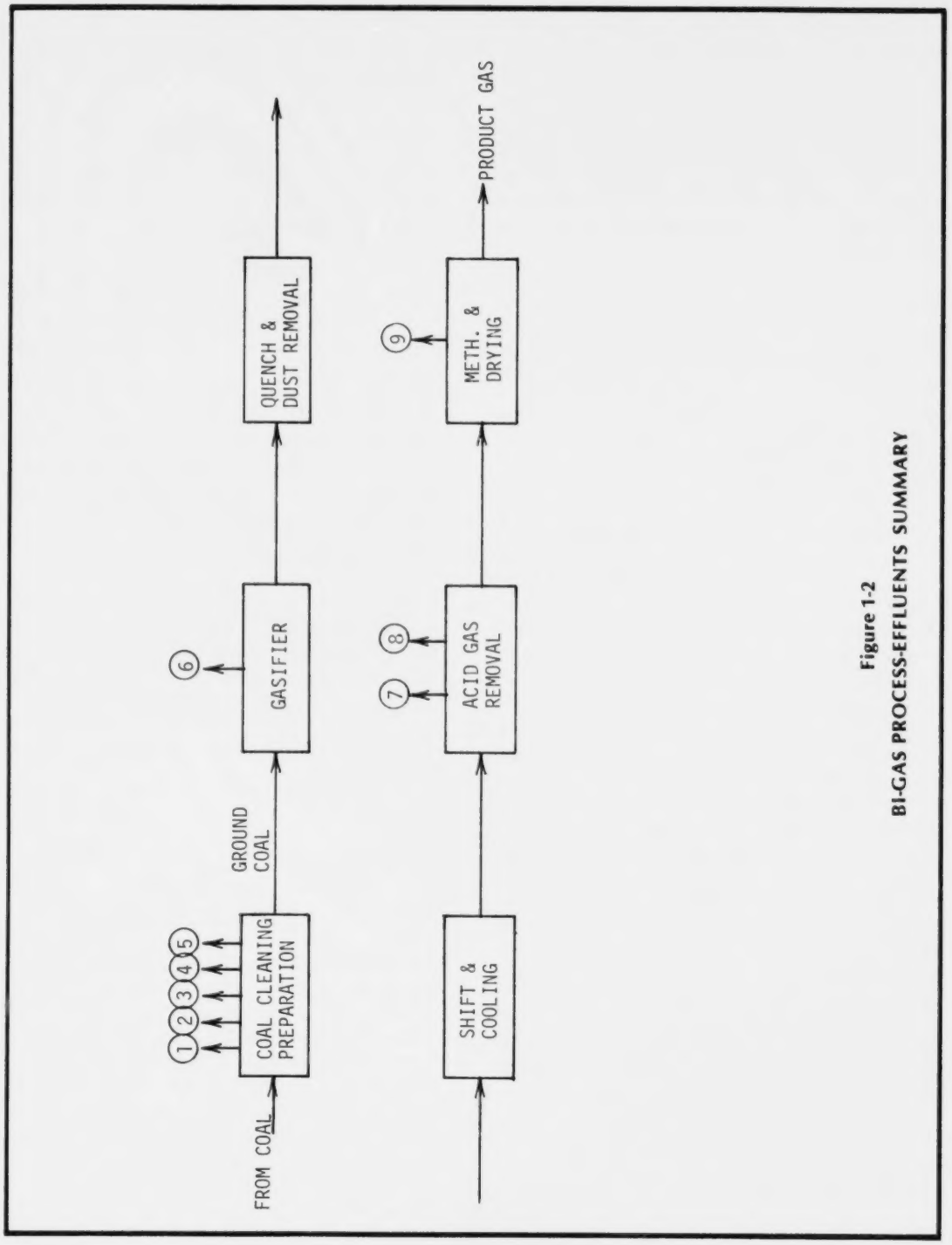

Figure 1-2
BI-GAS PROCESS-EFFLUENTS SUMMARY

BI-GAS PROCESS-EFFLUENTS SUMMARY FOR FIGURE 1-2

Stream #	Description
1	Wind-generated dust
2	Refuse
3	Wash water
4	Flue gas
5	Spent limestone
6	Gasifier slag
7	Chemical purge
8	Carbon dioxide vent stream
9	Water reject

Acid Gas Removal

Effluents to the Air - The BI-GAS pilot plant is currently investigating the use of the Selexol[R] solvent process for acid gas removal. This particular method vents the carbon dioxide removed from the product gas. This vent stream is relatively free of impurities and does not require further processing.

Liquid and Solid Effluents - The Selexol[R] Process does not create any liquid or solid discharges. If other types of processes are used, spent solution would be generated and disposal techniques would need to be devised.

Auxiliary Facilities

A generalized discussion of auxiliary facilities common to most coal conversion plants is given in Appendix A.

Sulfur Balance

A typical sulfur balance breakdown is given in Table 1-1.

Table 1-1
BI-GAS PROCESS SULFUR BALANCE

	percent
Claus plant	83.4
Claus plant tail gas	0.8
Flue gas coal dryer	1.0
Flue gas boiler	12.2
Flue gas superheater	2.6
	100.0

2. CO_2 ACCEPTOR PROCESS

The CO_2 Acceptor Process, located at Rapid City, South Dakota, is being developed by the Conoco Coal Development Company (CCDC) under the joint sponsorship of ERDA and AGA. ERDA is providing two-thirds of the funding and AGA, one-third. The initial contract for $27 million expired in June of 1976. Since that time another $3 million has been funded for plant operation.

2.1 PROCESS DESCRIPTION

A diagram of the CO_2 Acceptor Process is shown in Figure 2-1. In this process, raw coal is crushed to 8x100-mesh in hot, gas-swept impact mills, where the moisture content is reduced from approximately 38 weight percent to about 16 weight percent. The hot gas, at approximately 850°F, is supplied by the combustion of coal fines recovered from mill off-gas. The temperature of the furnace flue gas injected into the mills is moderated with recycle of mill off-gas.

The crushed and partially dried coal is dried to 0-5 weight percent moisture in flash driers operating about 240°F. The dried coal is conveyed to fluidized-bed preheaters where the temperature is raised to approximately 500°F. The preheated coal is then fed into the gasifier near the bottom of a fluidized-bed of char. Rapid devolatilization occurs, followed by gasification of the fixed carbon with steam.

The gasifier temperature ranges between 1,480°F and 1,550°F. Heat for the gasification reactions is supplied by a circulating stream of acceptor material. This acceptor, which can be either limestone or dolomite, supplies the heat needed for gasification, primarily through the exothermic carbon dioxide acceptor reaction:

$$CaO + CO_2 \rightarrow CaCO_3 + \text{heat}$$

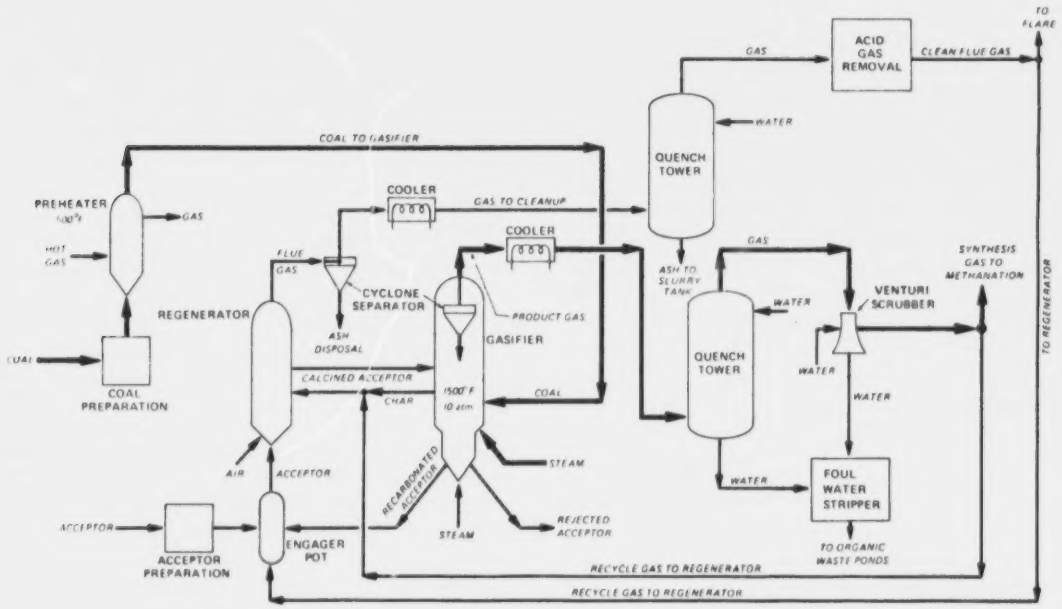

Figure 2-1
CO_2 ACCEPTOR PROCESS SCHEMATIC

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The acceptor, reduced to the desired size distribution (generally 6 x 14-mesh) enters the gasifiers above the fluidized char bed, showers through the bed, and collects in the gasifier boot. Steam needed for hydrogasification enters through the gasifier boot and the distributor ring. Spent dolomite, used during start-up to avoid plugging, is replaced by fresh acceptor after circulation rates are established and the system is at process temperature and pressure. Product gas from the gasifier passes through a steam-generating heat exchanger, then goes to the gas cleanup section.

The regenerator is used for calcining the acceptor. Carbonated acceptor from the gasifier flows through a standleg and is conveyed pneumatically by air or recycle gas to the bottom of the regenerator. Char from the gasifier is sent to the regenerator where it is burned with air, thus raising the temperature of the regenerator to 1,850°F. The acceptor is calcined by reversal of the carbon dioxide acceptor reaction. The calcined acceptor is returned to the gasifier through a standleg. Flue gas from the regenerator passes through a heat exchanger to generate steam for the gasifier and the air compressor.

Both the flue gas from the regenerator and the product gas are cleaned, the clean flue gas is either returned to the regenerator or flared, and the clean synthesis gas is sent to the methanation unit to raise the heating value of the gas to pipeline quality, approximately 1,000 Btu/SCF. The gas-processing facilities include a shift converter, carbon dioxide absorber, hydrodesulfurizer, zinc oxide sulfur guard, and a packed-tube methanator. A DOWTHERM^R system is used to remove the heat generated by the strongly exothermic methanation reaction.

2.2 PROCESS ADVANTAGES

- An oxygen plant is not needed because the acceptor is heated and calcined in a separate reactor where air can supply oxygen for combustion without contaminating product gas;
- The circulation rate is lower than that required in other high-Btu gasification processes that circulate solids for heat transfer, because the acceptor supplies heat through chemical reaction with carbon dioxide;
- Product gas cleanup requirements are minimized because the acceptor reacts with both hydrogen sulfide and carbon dioxide, the principal impurities in gasifier product gas;
- Raw gasifier product gas may contain enough hydrogen to methanate all of the carbon monoxide and part of the carbon dioxide without requiring water-gas shift conversion prior to methanation.

2.3 PROCESS LIMITATIONS

- Operating difficulties have been encountered in the area of solids circulation.

2.4 PROJECT HISTORY

Bench-scale development of the CO_2 Acceptor Process was completed in 1968. Feasibility studies indicated that the process had commercial potential. Construction of a pilot plant to test the process was completed, except for the gas-processing facility, in October 1971. Construction of the gas-processing facilities was completed in late 1974. The pilot plant is designed to use 40 tons of coal and 3 tons of dolomite per day to produce 500,000 SCF of high-Btu gas.

Pilot plant shakedown operations began in January 1972 and were completed in April 1972. A series of start-up attempts were initiated followed by the experimental run program. Along with the operation of the pilot plant, CCDC has been continuing its laboratory research to resolve problems and improve the overall process design.

During 1975, runs were made in the pilot plant. Most of the runs were instrumental in locating operational problems. As these problems were solved, progressively longer and more trouble-free runs were made. During one of the successful runs, the system operated for 232 consecutive hours without air to the gasifier and 87.5 hours with 100 percent steam to the gasifier. The unit also operated 72 hours with

no air or recycle gas and all steam. The packed-tube methanation unit was also successfully operated for 48 hours without mechanical difficulty. The heating value of the synthesis gas was upgraded from 373 to 787 Btu/SCF. It is expected that this will be increased to 900 Btu/SCF when the newly installed hot potassium carbonate acid gas cleanup system is fine-tuned.

2.5 ENVIRONMENTAL CONSIDERATIONS

This process generally meets the emissions standards set for major pollutants. However, there is one unique area of concern about exceeding standards.

This uniqueness involves the lignite feedstock (as opposed to bituminous feedstock for other processes) which has a high moisture content and must be dried prior to gasification. Initially, raw lignite containing approximately 33 percent moisture is fed to a grinder which is swept with hot recirculating gas to dry the lignite down to 16 percent moisture. The coal is then fed through a drier and a preheater before being fed to the gasifier. The three furnaces used to supply heat to the grinder/drier/preheater system are required to use a mixture of 25 percent raw fuel gas, derived from the process, and 75 percent lignite as fuel in order to achieve the limit of 1.2 lb/MM Btu sulfer dioxide emissions. This particular mixture will vary, depending on the sulfur content of the lignite feed, and is an important parameter since an error in mixing could throw the furnaces out of compliance. In addition, combustion of lignite fuels generates ash which needs to be separated and rejected. Slagging type furnaces are used where an estimated 70 percent of the ash is removed in the reject slag. Hot gas leaving the furnace is cooled and passed through cyclones to remove rearly all of the remaining ash. If the final ash content of the hot gas is comparable to the 0.1 lbs/MM Btu required on stationary boilers, then overall separation of the ash must be 99 percent effective. This degree of separation has been difficult to achieve with conventional cyclones in power plant boilers using as fuel.

When the hot gas contacts lignite in the grinder, some of the lignite fines are entrained in the gas stream and need to be recovered. In order to meet the comparable dust loading of 0.1 lbs/MM Btu, the dust remaining in the vent gas after final cleanup can only be 155 lbs/hr. This requirement represents a difficult cleanup problem since it corresponds to only 0.1 weight percent of the lignite charge on a dry basis. A number of dust removal systems will need to be examined and tested in order to meet dust-loading standards.

Another concern with emissions from the coal preparation area involves odors. Lignite is a relatively reactive material, and when dried and preheated to 500°F small amounts of vapors are evolved. These vapors may have undesirable odors; incineration of the effluent gas may be necessary.

The process effluents summaries described later relate to a future commercial-sized plant and are either estimated from current pilot plant data or, if necessary, from design data. The process effluents summary is shown in Figure 2-2.

Coal Preparation and Drying

Various pollutants are discharged from this area. Since coal preparation is common to all coal conversion plants, a generalized discussion is given in Appendix B.

Gasification

Effluents to the Air - There will be no gaseous streams released directly to the atmosphere from the gasifier. However, a stream of spent dolomite acceptor, $MgO\text{-}CaCO_3$, will be removed from the gasifier to maintain acceptor activity. The possibility of a dust problem may exist if proper handling procedures are not followed. If dusting problems are encountered, an enclosed fluid-bed cooler could be used to cool the acceptor and control any resulting dust.

Liquid and Solid Effluents - The only discharge stream from the gasifier will be the reject acceptor which is replaced at the rate of 2 percent per day of dolomite circulation. The reject acceptor is expected to be low in sulfur, 0.084 percent from pilot plant data, and is not expected to pose a secondary pollution problem if used as landfill material.

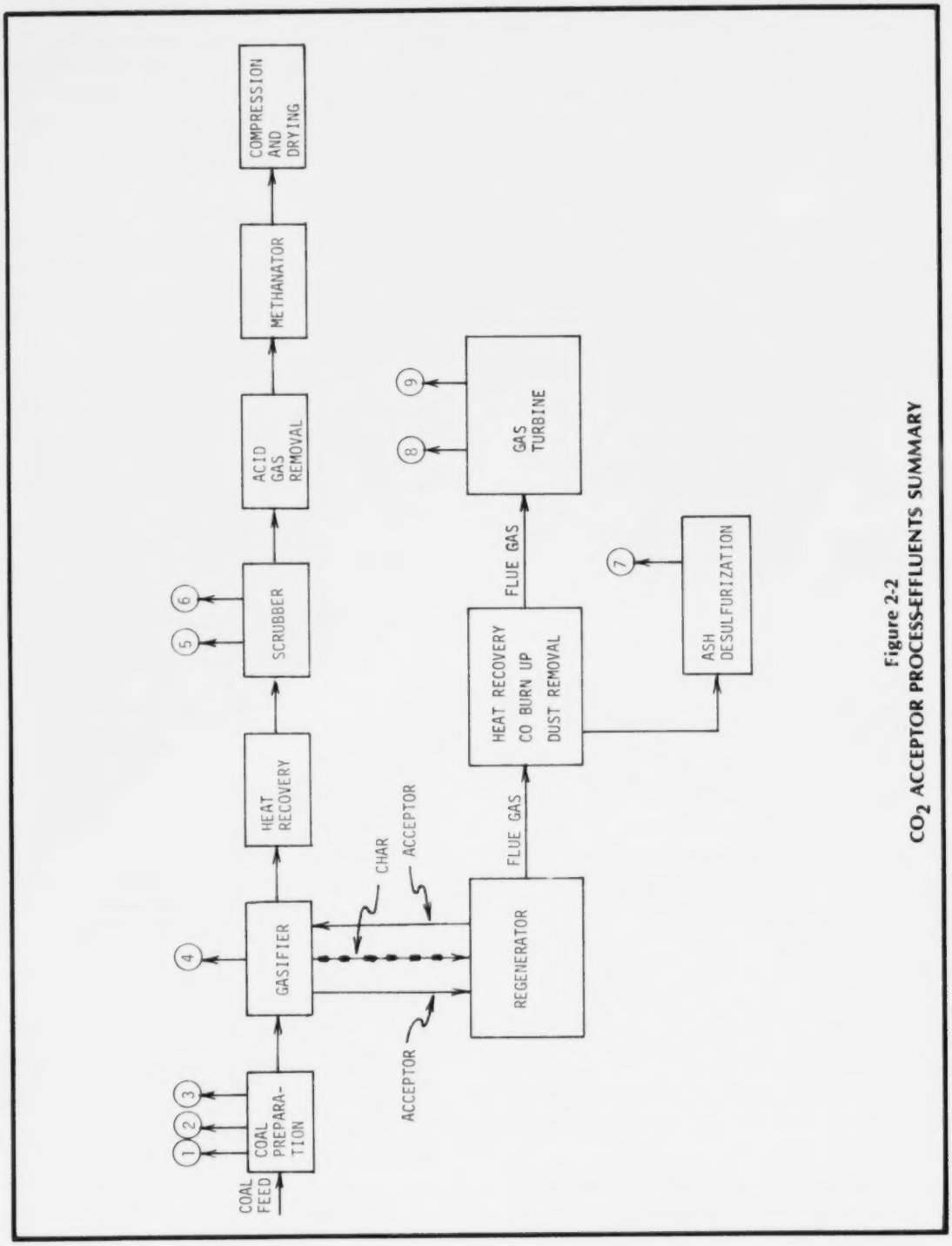

Figure 2-2
CO_2 ACCEPTOR PROCESS-EFFLUENTS SUMMARY

CO_2 ACCEPTOR PROCESS-EFFLUENTS SUMMARY FOR FIGURE 2-2

Stream #	Description
1	Rain runoff
2	Vent gas from dryer
3	Ash from dryer fuel
4	Reject acceptor
5	Warm air
6	Chemical purge
7	Ash slurry
8	Flue gas from turbine
9	Dust

Raw Gas Cleaning/Acid Gas Removal

Effluents to the Air - There will be no streams discharged directly to the environment from these units. However, there are various waste streams that will be created here which must be treated before disposal or use as a make-up stream.

As raw gas leaves the gasifier, it is initially cleaned by an internal cyclone. The gas is then cooled by a water stream in a wash cooler which removes the residual dust and ammonia. The water stream will also contain sulfur compounds since the gas stream could contain as much as 3,300 ppm of hydrogen sulfide. The water will be required to be treated in a clarifier to remove solids; processed in a sour water stripper to remove ammonia and hydrogen sulfide; and then finally processed in a biox (biological oxidation) unit to remove the traces of phenols, tar, and naphthalene. A retention pond would also be required to reduce contaminants to allow use as recycle stream. This water should not be allowed to become an effluent from the plant.

A small purge stream of amine used for acid gas removal will be periodically removed from the system. This stream must be treated and is usually dumped into a holding vessel for further disposal with other chemical effluent streams.

Liquid and Solid Effluents - No effluents will be discharged.

Methanation

Effluents to Air - No effluents will be discharged.

Liquid and Solid Effluents - In general, there will be no liquids discharged from the unit. The spent nickel catalyst discharge will be returned to the processor for metals recovery.

Regenerator

Effluents to the Air - In pilot plant operation the circulating dolomite acceptor is calcined at 1,850°F to remove carbon dioxide. Heat is supplied by burning the char contained in the acceptor from the gasifier with air in the fluid-bed regenerator operating at 150 psig. The flue gas from the process is cleaned of dust in cyclone separators and then goes to an expansion turbine to recover power. The flue gas is discharged to the atmosphere at this point. It contains 470 ppm of total sulfur and acceptable levels of nitrogen oxides and dust. Various operating parameters require close attention, however, in order to assure proper nitrogen oxide levels. Several combustion stages are present where excessive nitrogen oxide formation could take place. This procedure will be the same for a commercial operation with similar emission levels expected.

Liquid and Solid Effluents - There will be no liquid effluents from the unit, and the only solid stream is an ash stream which is recovered in the flue gas cyclones. For a 27,500 TPD plant, this ash would amount to 177,000 lb/hr. However, disposal problems do exist since the ash has a 5.0 weight percent sulfur content (carbon is only 3.5 weight percent) which is in the form of compounds such as calcium sulfide that would release hydrogen sulfide. This particular material will require desulfurization before disposal.

Auxiliary Facilities

A generalized discussion of auxiliary facilities common to most coal conversion plants is given in Appendix A.

Sulfur Balance

The distribution of the sulfur in the lignite feed to plant is broken down as shown in Table 2-1.

Table 2-1
CO_2 ACCEPTOR PROCESS SULFUR BALANCE

	percent
By-product sulfur	72.4
Reject acceptor	1.0
Spent ash	1.3
Regenerator flue gas	16.9
Dryer vent gas	6.2
Claus tail gas	2.2
	100.0

3. COALCON HYDROCARBONIZATION PROCESS

Coalcon Company, Inc., an affiliate of Union Carbide, is to verify, through a demonstration-sized plant, the commercial economics, technical scale-up potential, and the physical and chemical feasibility of a process for producing clean boiler fuels from high-sulfur coal and pipeline gas and other useful products in a commercial-sized plant. The design phase is estimated to cost near $20 million. Construction costs were expected to be $142.3 million (1974 dollars), and the operating phase $72.5 million. However, due to a number of technical and management problems, a "go-slow" approach has been taken.

The plant was designed to convert 3,901 TPD of high-sulfur coal into 2,990 BPD of heavy oil, 1,192 BPD of gasoline fraction, 1,088 MMSCFD of SPG, and 28.93 MMSCFD of high-Btu pipeline quality gas. Some 125.6 TPD of elemental sulfur will also be produced. The plant was to be built on a site just outside New Athens, Illinois.

3.1 PROCESS DESCRIPTION

The method selected by Coalcon for producing clean boiler fuel in the demonstration plant is Union Carbide's Hydrocarbonization Process. The conceptual design of the plant using this process is divided into five main areas: (1) coal preparation, (2) the hydrocarbonization reactor, (3) reactor product cooling and liquids separation, (4) gas processing, and (5) hydrogen generation. The process flow diagram is shown in Figure 3-1.

Initially, the coal is crushed, milled, and classified, then fed to the coal preheater. The heating scheme involves entraining the coal in a hot, oxygen-free flue gas and separating the solids from the gas in a cyclone. This heating process helps maintain the reactor heat balance and also drives off some volatiles and moisture. After heating to about 617°F, the coal is held in the coal feed

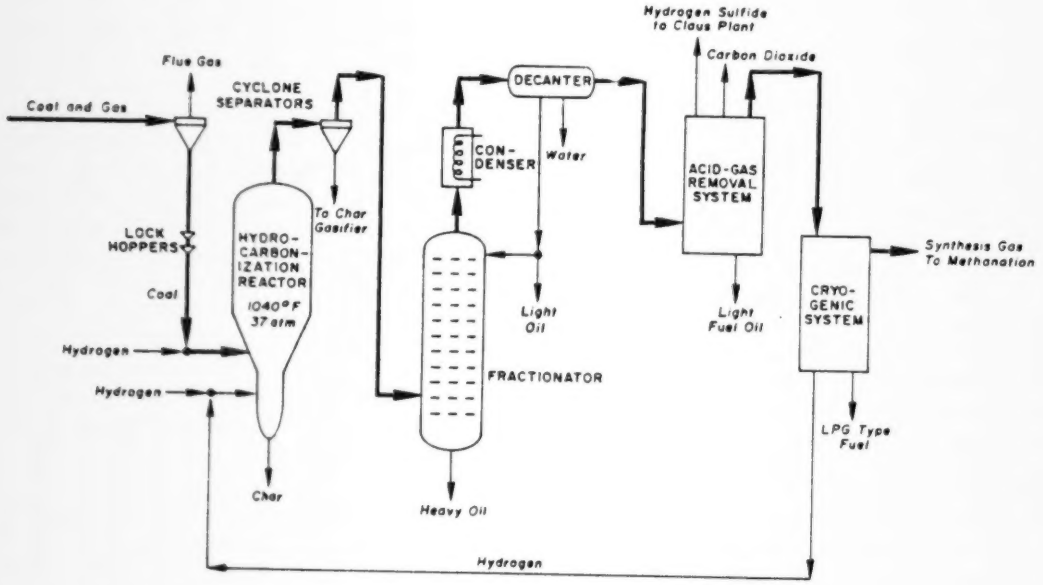

Figure 3-1
COALCON PROCESS SCHEMATIC

hopper before it is pressurized to the operating pressure of the system, approximately 51 atm. The coal is dropped from the lock hoppers into another coal holding vessel. From there, it is gravity fed into an injection vessel where it is fluidized with hydrogen at 1,040°F and 53 atm. This mixture enters the hydrocarbonization reactor which operates at 37 atm and 1,040°F. The solid residence time in the reactor is approximately 25 minutes. The solids not gasified are removed from the reactor through an agglomerate removal system at the bottom of the reactor. This char is used to manufacture hydrogen and also may be used to generate steam.

The gas residence time in the bed is approximately 25 seconds. These gases are heavily laden with solids which subsequently are removed by two cyclones. The cleaned gas/vapor from the cyclones is sent downstream to the fractionator for cooling and separation. The basic purpose of the fractionator is to split the reactor product into four basic streams:

- Overhead gas (hydrogen, carbon monoxide, carbon dioxide, methane)
- Light liquid (#2 fuel oil)
- Heavy liquid (#5 or #6 fuel oil)
- Waste water

The heavy oil from the bottom of the fractionator is partially cooled and recycled to a venturi where it mixes with the hot reactor product gas. This mixture is fed to the fractionator and split into a hot heavy fuel oil and a moderately hot (350°F) fractionator overhead stream. The heavy oil product is cooled to about 104°F and pumped to storage. The fractionator overhead is condensed and the liquid/vapor mixture is fed to a decanter where the light fuel oil, overhead gas, and waste water are separated. Some of the light oil is sent to the fractionator as reflux and the remainder is sent to storage as product. The remaining gas is sent through a series of separation and purification systems which include ammonia removal and recovery, acid gas removal (hydrogen sulfide, carbon dioxide), and a cryogenic gas-producing system. The cryogenic system manufactures LP fuel gas, synthesis gas, and a hydrogen-rich stream. The hydrogen stream is recycled back to the hydrocarbonization reactor while the synthesis gas is sent to a methanation reactor for upgrading to high-Btu pipeline gas. The LP fuel gas may be either burned on-site or sold.

3.2 PROCESS ADVANTAGES

- The plant will be fully integrated in all phases of processing, from receipt of coal to delivery of a finished product;
- The process yields a multiple product.

3.3 PROCESS LIMITATIONS

- ERDA has reported that the process economics are marginal and technical problems with the fluid-bed are greater than first believed.

3.4 PROJECT HISTORY

Work under this ERDA contract was initiated in January 1975. Union Carbide was selected to design, construct, and operate a demonstration plant for producing clean boiler fuels from high-sulfur coal.

During 1975, work on the Clean Boiler Fuel Demonstration Plant involved preliminary process design and engineering of a commercial plant. This effort included review and evaluation of all hydrocarbonization subsystems to minimize capital investment and maximize subsystem operability and reliability. By the end of 1975, design and engineering for the commercial plant were near completion. A process evaluation report was prepared and submitted to ERDA. This report includes preliminary data on plant design and provides a basis for starting the design of the demonstration plant.

Work toward establishing the definition and design basis for the demonstration plant began late in 1975. The plant will be one-fifth the size of a commercial-scale plant and will be capable of utilizing three different types of coal. Preliminary performance specifications were issued, and

work on the overall process design of the demonstration plant, analysis of the three coal types to be tested, and development of process designs of plant subsystems were started.

Design of the demonstration plant was continued in 1976. However, about midyear, a number of technical and management problems began to plague the project. ERDA, later in the year, ordered a "go-slow" approach to design and procurement activities. At this time, ERDA and Coalcon are negotiating a continuance of design phase activities, and Coalcon has made a proposal to ERDA to fund a pilot plant to generate gasifier data on caking eastern coals. This is probably necessary due to a data gap that became apparent due to design activites using old laboratory data generated by Union Carbide in the 1960's and results obtained by current laboratory testing of eastern coals in a bench-scale reactor.

The initial plant design is 100 percent funded by ERDA while the construction and operation is on a 50-50 cost sharing basis with government and industry. At present, the potential participants include: Atlantic Richfield Company, Ashland Oil, Mobil Research and Development Corp., Du Pont, Reynolds Metals, Consolidated Gas, State of Illinois, Northern Natural Gas, Ohio Power, Pacific Gas and Electric, Electric Power Research Institute (EPRI), and Celanese Corporation.

3.5 ENVIRONMENTAL CONSIDERATIONS

The Coalcon Process produces both liquid and gaseous products. However, the basic downstream processing for gas cleanup and liquid product recovery is the same as the other processes covered. Very little public data exists on the environmental aspects of this process since much of the development work was done in the 1960's on a laboratory scale. There have been some evaluations made by the Coalcon design team but the information has not yet been made public. From all indications, pollution problems or plant effluents resemble those of refineries and should be handled by existing technology.

Auxiliary Facilities

A generalized discussion of auxiliary facilities common to most coal conversion plants is given in Appendix A.

Sulfur Balance

A typical sulfur balance breakdown is given in Table 3-1.

Table 3-1
COALCON PROCESS SULFUR BALANCE

	percent
Heavy fuel oil	0.3
Gasoline fraction	0.2
Elemental sulfur	93.3
Atmospheric vents	5.4
Ash	0.8
	100.0

4. HYGAS PROCESS

The HYGAS Process is being developed by the Institute of Gas Technology (IGT) as part of the joint program of ERDA and the AGA. ERDA is providing two-thirds and AGA one-third of the $8 million contract funding. The HYGAS pilot plant is located in Chicago, Illinois.

4.1 PROCESS DESCRIPTION

Several processing steps are required to convert coal to high-Btu gas with the HYGAS Process. A key feature is the use of hydrogen and steam in hydrogasification. A diagram of the process is provided in Figure 4-1. Coal preparation involves crushing the coal to -8-mesh. Caking coal is pretreated in a fluidized-bed at 660°F to 750°F and at atmospheric pressure to destroy caking tendencies and produce a free-flowing coal. Noncaking coal is fed directly into the slurry tank. The coal is mixed in this tank with an aromatic recycle oil to form a thick slurry and is pressurized to 1,000 psig. The slurry is then sprayed into the drying section of the gasifier.

In the drying section, oil is vaporized and removed, together with the hot gases passing upward from the first stage of the gasifier. Vaporized oil is recovered for reuse by quenching the effluent of the gasifier.

The dried coal drops into the first stage of the gasifier where it is heated rapidly by internally recycled hot char and hot reaction gases rising from the second-stage reactor. The relatively low temperature environment of the first stage provides for conversion of approximately 20 percent of the feed coal to methane. At the top of the first stage the diameter of the reactor increases rapidly thus reducing the velocity of the upward-flowing gases and solids. At these lower velocities, the

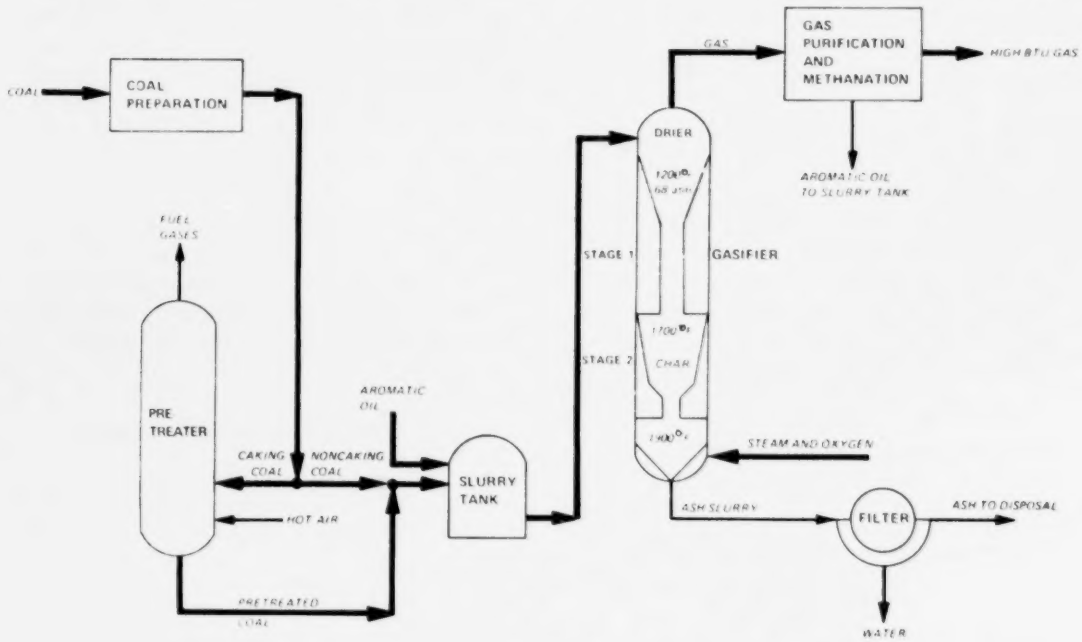

Figure 4 - 1
HYGAS PROCESS SCHEMATIC

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partially spent char is separated from the gas and channeled downward. Part of this hot char is recycled to provide heat to the first stage, and the remainder is sent to the second hydrogasification stage, a high-temperature fluidized-bed reactor. An additional 25 percent of the raw coal feed is converted to methane in the hydrogen-rich environment of this stage. Hot residual char moves from this stage into the steam-oxygen section in the bottom of the reactor. Here, the steam, oxygen, and char react in a fluidized-bed, producing a hydrogen-rich gas. This gas is transferred up into the hydrogasification sections as a source of hydrogen for methanation reactions. Ash is removed from the bottom of the stream-oxygen stage.

The product gas, containing methane, carbon monoxide, carbon dioxide, hydrogen, and other raw gases, particulates, trace elements, and water and oil vapors, is quenched, purified, and passed to the methanator. The mole ratio of hydrogen to carbon monoxide in the gas is adjusted to a ratio of about 3:1 prior to entering the methanator. In the methanator, the gas passes through a nickel catalyst at 800°F to 900°F and is transformed to methane, providing a pipeline quality gas with an average heating value of 1,000 Btu/SCF.

4.2 PROCESS ADVANTAGES

- Use of a steam-iron reactor eliminates the need for a large oxygen or power-plant, reduces the amount of carbon dioxide scrubbing required, and eliminates downstream shift reactors by proper adjustment of the steam-hydrogen ratio;
- Energy recovery and sale of by-product electricity may lead to an overall coal-to-energy conversion of greater than 70 percent.

4.3 PROCESS LIMITATIONS

- Supplemental hydrogen is required;
- Some feed coal types require pretreatment.

4.4 PROJECT HISTORY

Development of the HYGAS Process by IGT under the sponsorship of AGA began in 1946 and continued under joint sponsorship with the Office of Coal Research (OCR, now a part of ERDA) in 1964. The pilot plant was designed and built to convert 75 tons of coal per day to 1.5 million cubic feet of clean high-Btu gas. During 1973, the plant produced pipeline-quality gas from coal in sustained test operations. Since then, the duration of the test runs has increased, and longer, more stable operating periods have been achieved.

During 1975, 11 test runs were made in the HYGAS pilot plant. The longest run was 363 hours, during which 575 tons of lignite were fed to the gasifier. Based on the success of this test, authorization was given to begin testing with Illinois No. 6 bituminous coal.

Also during 1975, 26 runs were made with the ash-agglomerating gasifier. Process parameters were varied to determine the optimum operating conditions. During one run, agglomerates were successfully produced for a 200-hour steady-state period, and full dust recycle was maintained.

In 1977 IGT achieved 92 percent carbon conversion efficiency in tests with Illinois No. 6 coal. The conversion was achieved at 1,000 psig without slagging and was attained in the steam-oxygen gasification stage of the reactor at a temperature of 1,700°F. This was significantly lower than the expected reaction temperature of around 1,800°F.

Concurrent laboratory research was directed toward the study of the penetration of slurry liquid into coal pores, effects of acidic condensing atmospheres on castable insulations, lock hopper design, and methanation catalyst evaluation.

4.5 ENVIRONMENTAL CONSIDERATIONS

The use of caking coal requires pretreatment without which agglomeration in the fluid-bed occurs causing plugging. The environmental effects would be altered by such pretreatment. The IGT is currently extending the environmental assessment to cover the pretreatment step. This report addresses itself to the use of non-caking coal. The process effluents summary is given in Figure 4-2.

Coal Preparation

In addition to pretreatment effects previously mentioned, various other pollutants are discharged from this area. Since coal preparation is common to all coal conversion plants, a generalized discussion is given in Appendix B.

Slurry Preparation

Effluents to the Air - Any flash gas released during slurry formation of hot recycle oil and coal must be recovered and used, or incinerated.

Liquid and Solid Effluents - No effluents are discharged.

Gasification

Effluents to the Air - The major effluent from gasification during normal operation is the residual char that contains ash that enters with the coal feed. This char, containing 10 to 30 percent carbon, is quenched with water, depressured by lock hoppers, and sent to an ash-settling pond. Steam formed by this quenching operation may contain particulates and other contaminants; it can be returned to the process or collected for disposal. The amount of steam is approximately 50,000 lb/hr. In the operation there should be no serious emissions to the atmosphere.

Ash in the water slurry is recovered in a settling pond, which is drained so that semi-dry ash can be removed for burial.

Attrition of particles in the HYGAS reactor will generate fines that are carried up with the gas stream. These fines will be removed rather completely by the oil quench system, thus tending to build up in concentration in the recycle oil unless they are removed by agglomeration, filtration, or other means. Similarily, volatile trace elements may accumulate in the recycle oil.

Liquid and Solid Effluents - The major effluent from the gasification area of the plant is spent char, which serves to reject ash brought in with the coal feed. Some unreacted carbon is also rejected in the char. Hot char from the gasifier is handled by quenching in water, forming steam which is presumably returned to the gasifier, and a water slurry, 25 percent solids, which is depressured across an oil-field type choke. The slurry goes to a settling pond from which water is recycled to the quench system. At intervals, the pond is drained so that wet ash can be reclaimed for ultimate disposal off-site.

Quench and Dust Removal

Effluents to the Air - Gas from the gasifier, together with slurry oil evaporated in the drying zone is quenched to 400°F by direct contact with recirculated oil, the heat being used to generate steam in waste heat boilers. Most of the oil vapor in the entering gas is condensed and recycled to slurry preparation, while at the same time particulates and condensibles such as trace elements will be removed from the gas and will accumulate in the oil. While most of the oil is recycled, part of it must be withdrawn as product and can be expected to contain toxic elements such as arsenic, lead, and cadmium, as well as particulates, phenols, and sulfur and nitrogen compounds. Therefore the properties of this oil and its projected secondary use need further evaluation to define what treatment may be required to make it suitable for use as fuel or as a raw material for refining.

Liquid and Solid Effluents - In this area of the process, raw gas is cooled by direct contact with product oil which is recirculated and cooled. At the same time, particulates in the raw gas are removed. While most of the oil is used as a slurry for the coal feed, a stream of by-product oil is also withdrawn corresponding to the net yield of oil from the coal gasification reaction. This by-product oil, amounting to 338 TPD is the only major effluent from this section of the process. One possibility is to use it for fuel, but more information is required to determine whether it can be burned directly, or if it will first need further treatments to remove contaminants.

When the oil is condensed upon cooling, most of the dust in the raw gas leaving the

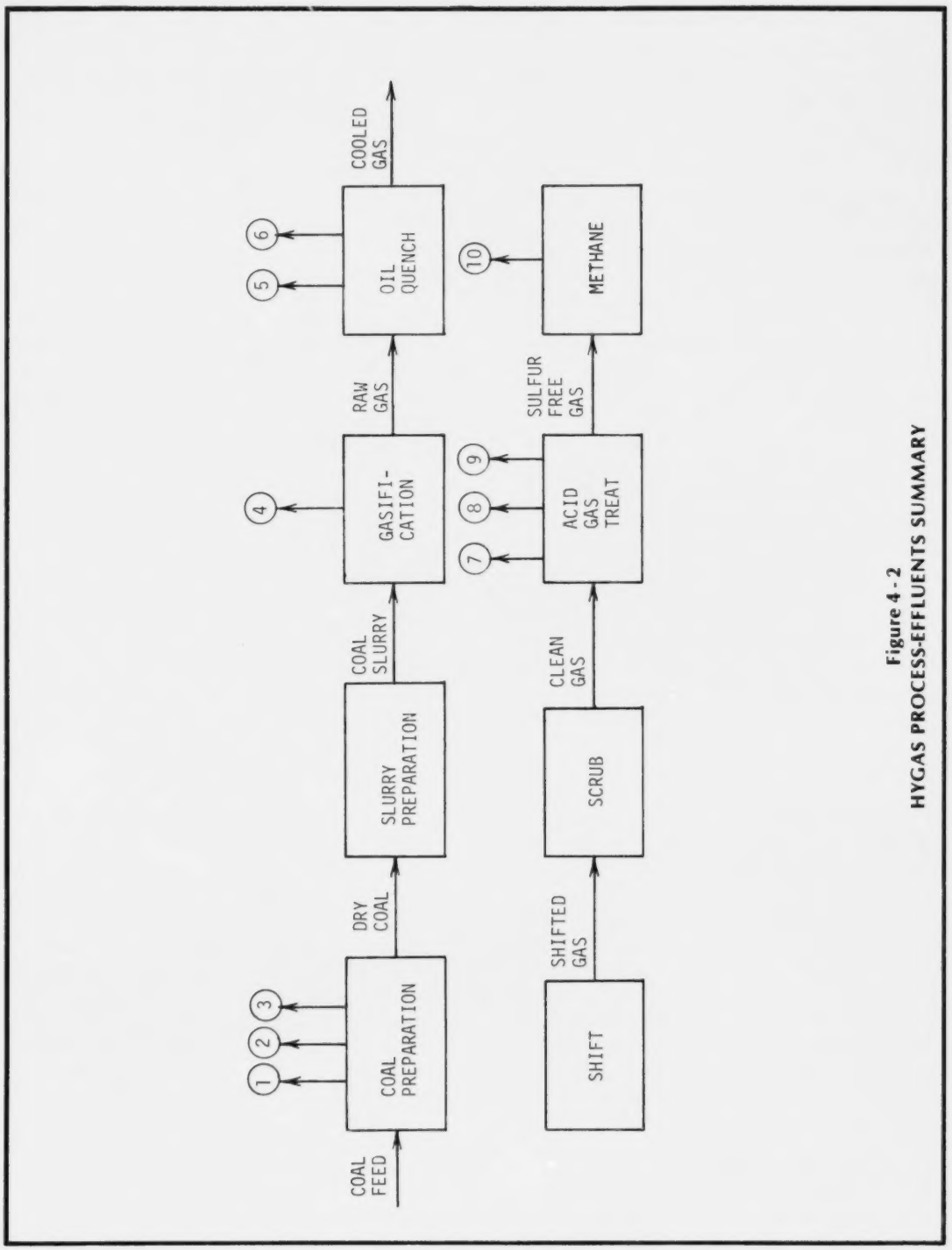

Figure 4 - 2
HYGAS PROCESS-EFFLUENTS SUMMARY

HYGAS PROCESS-EFFLUENTS SUMMARY FOR FIGURE 4-2

Stream #	Description
1	Dust
2	Water
3	Flue gas
4	Char slurry
*5	By-product oil
6	Fine solids
7	Carbon dioxide vent gas
*8	By-product oil
9	Chemical purge
10	Water purge

*Product, not an effluent

drying bed will also be removed. The condensed oil is recycled and used for coal feed slurry.

Shift Conversion

Effluents to the Air - In this process the carbon monoxide is shifted by reaction with steam to to produce hydrogen. This catalytic operation may also give some hydrogenation to help remove ofefins, cyanides, and oil vapor. It may also be possible to modify the shift reactor to hydrolize carbonyl sulfide and other compounds to form hydrogen sulfide which is removed more easily in acid gas treatment. Some trace elements and coke are expected to be deposited on the shift catalyst; reprocessing or proper disposal will be undertaken periodically.

When the gas liquor is depressured, gases are released that will be recovered or incinerated. In addition, sour water stripping produces by-product ammonia and hydrogen sulfide which can be sent to sulfur recovery.

If there is residual dust in the gas that leaves the oil quench system, it will be removed in the scrubber.

Liquid and Solid Effluents - Shift conversion does not involve primary emissions or effluents, although some trace elements and tarry materials may accumulate on the fixed-bed of catalyst used in this operation. Subsequent cooling and scrubbing of the gas, however, condenses a large amount of sour water which will be cleaned and reused or properly removed. Some oil is also condensed; it is returned to the oil quench system after separation from the water layer.

Phenols can be separated by extraction (e.g., Phenosolvan^{R} Process), while sour water stripping will remove ammonia and hydrogen sulfide for recovery. Biological oxidation may then be used for further cleanup of waste water, followed by filtration or activated carbon processing as required

Acid Gas Removal

Effluents to the Air - In this process the bulk of contaminants remaining in the gas are removed. Major constituents are acid gases, hydrogen sulfide, 1.44 percent by volume, and carbon dioxide, 30.85 percent by volume, while minor contaminants include hydrogen cyanide, ammonia, light hydrocarbons, and naphtha. Acid gas treatment will remove all contaminants to a low level while providing a concentrated sulfur-containing stream to the sulfur plant with a carbon dioxide waste stream, which is pure enough to be vented directly to the atmosphere without further treatment.

The IGT design uses a Lurgi Rectisol^{R} system for acid gas treatment based on scrubbing with refrigerated methanol. The design shows 30 percent by volume concentration of sulfur compounds in the gas fed to the Claus plant. This amount represents a desirably high concentration to allow efficient sulfur recovery.

The carbon dioxide rejected to the atmosphere is a very large stream, the TPD exceeding the daily total of coal used by the plant. It will therefore be particularly free of contaminants in a concentrated form. Sulfur content at 300 ppm is moderate, amounting to less than 1 percent of the sulfur in the coal to gasification.

This content would appear acceptable in some cases depending on standards that apply for a

specific location, at least if it were in a less objectionable form such as sulfur dioxide.

Liquid and Solid Effluents - The primary liquid effluent from acid gas treatment is a naphtha and oil mixture which is recovered from the gas by scrubbing with refrigerated methanol. This oil is returned to the oil quench system and is eventually withdrawn as a by-product. As a result of the high cracking severity to which the oil has been exposed in the gasification reactor, it will consist mainly of aromatics such as benzene and should be useful as a raw material for making chemicals or gasoline. Benzene is toxic so proper handling and storage precautions are needed.

There is also a small amount of water rejected from acid gas treatment, which can be combined with sour water from scrubbing for treatment.

There should be no significant solid effluents from acid gas treatment since char and ash particles will be removed in the scrubber.

Methanation and Drying

Effluents to the Air - Methanation and drying are carried out in a closed system with no streams normally emitted to the atmosphere. Proper design and operation will control leaks from this system. Gas released when depressuring water, or when depressuring equipment for maintenance, will be collected and recovered or incinerated.

Liquid and Solid Effluents - The methanation reaction produces a large amount of water which is condensed and used for makeup to steam boilers. The amount is large relative to the net waste water effluent and thus makes an important contribution in the overall water balance. It is a very clean condensate, free of sulfur and dissolved solids, so little or no treating is required.

Auxiliary Facilities

A general discussion of auxiliary facilities common to most coal conversion plants is given in Appendix A.

Sulfur Balance

A typical sulfur balance breakdown is given in Table 4-1.

Table 4-1
HYGAS PROCESS SULFUR BALANCE

	percent
Dryer vent gas	0.2
Carbon dioxide	0.3
Tail gas	1.0
Sulfur	96.4
Flue gas	0.9
Char	1.0
Other	0.2
	100.0

5. KOPPERS-TOTZEK GASIFICATION PROCESS

The licensors/developers of the Koppers-Totzek Gasification Process are Heinrich Koppers GmbH, Essen, Germany, and the Koppers Company, Inc., Pittsburgh, Pennsylvania. The process function involves atmospheric pressure coal gasification in an entrained-bed by injection of coal plus steam plus oxygen with co-current gas/solid flow. The process has been commercially available since the early 1950's. There are currently 20 plants in operation with 52 gasifier units, none operating in the U.S. However, Air Products and Chemicals, Inc., Allentown, Pennsylvania, has been selected by ERDA to negotiate for the design, construction, and operation of a facility for use in industrial processes. To be located at Cedar Bayou, Texas, the facility is expected to cost around $100 million.

5.1 PROCESS DESCRIPTION

The Koppers-Totzek Gasification Process employs the partial oxidation of a carbonaceous feed in suspension with oxygen and steam to produce a clean, medium-Btu gas which can be readily desulfurized. The product gas is high in carbon monoxide and hydrogen with a negligible amount of methane. By-products are elemental sulfur and a granulated sulfur-free slag. A schematic of the Koppers-Totzek Process is provided in Figure 5-1. There are four major steps in the process: (1) feed preparation, (2) gasification, (3) heat recovery and gas cleaning, and (4) hydrogen sulfide removal and sulfur recovery.

Raw coal is dried and pulverized so that approximately 70 percent will pass through 200-mesh. The coal is conveyed with nitrogen from storage to the gasifier service bins. Controls regulate intermittent feeding of coal to the feed bins. The bins are connected to twin variable-speed coal screw feeders. The coal is discharged into a mixing nozzle where it is entrained in oxygen and low-pressure steam. The mixture is then delivered through a transfer pipe to the burner head of the gasifier.

The oxygen, steam, and coal react in the refractory-lined steel shell gasifier at a slight positive pressure, 5 to 7 psig. Reaction temperature at the burner discharge is 3,300°F to 3,500°F. Gasification of the coal is almost complete and instantaneous. Carbon conversion is a function of the reactivity of the coal, approaching 100 percent for lignites. Low-pressure process steam for the gasifier reaction is produced in the gasifier jacket from the heat passing through the refractory lining.

Ash in the coal feed is liquefied in the high temperature zone. Approximately 50 to 70 percent of the molten slag drops out of the gasifier into a slag quench tank and is recovered for disposal as a granular solid. The remainder of the slag and all the unreacted carbon are entrained in the gas exiting the gasifier. Water sprays quench the gas to drop the temperature below the ash fusion temperature to prevent slag particles from adhering to the tubes of the waste heat boiler mounted atop the gasifier.

The raw gas from the gasifier passes through the waste heat boiler where high-pressure steam, up to 1,500 psig, is produced. After leaving the waste heat boiler, the gas at 350°F is cleaned and cooled in a high energy scrubbing system. The system consists of a fixed venturi-type scrubber, for removing the largest particles, 95 percent of total, and a variable venturi-type scrubber for removing more than 99 percent of the remaining particles. The entrained solids in the gas are thus reduced to 0.002 to 0.003 grains per SCF. Following scrubbing, the gas is cooled with water to about 95°F in a packed cooler. If the gas is to be compressed to high pressure for chemical synthesis, electrostatic precipitators are used for further cleaning. Several gasifiers can share common cleaning and cooling equipment.

Particulate-laden water from the gas cleaning and cooling system is piped to a clarifier. Clarified water is recirculated through the venturi

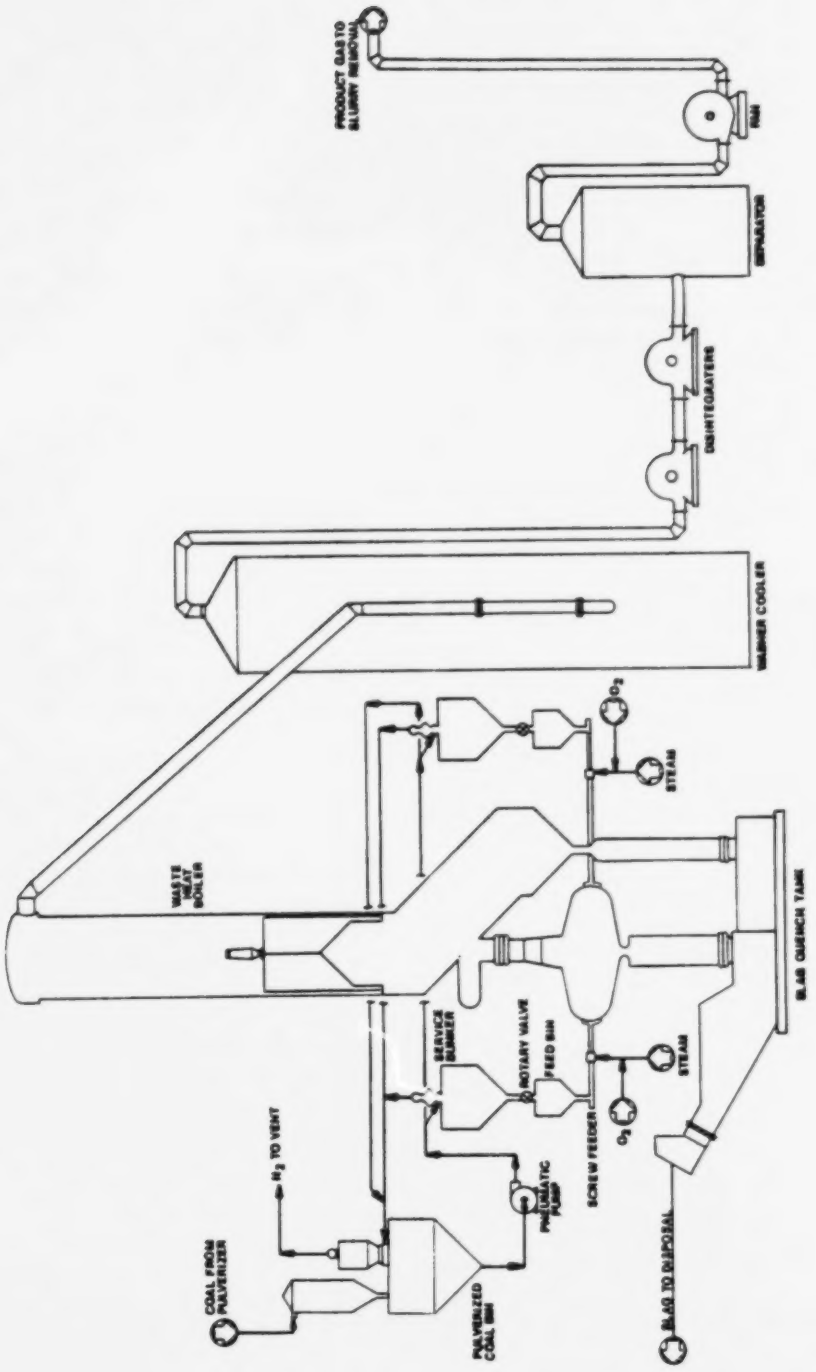

Figure 5-1
KOPPERS-TOTZEK PROCESS SCHEMATIC

scrubbers and the excess overflows into the cooling tower system at the gas cooler. Sludge from the clarifier is pumped either to a filter or to the plant disposal area.

The cool, clean gas leaving the gas cleaning system contains sulfur compounds which must be removed. The type of system chosen depends upon the end uses and desired pressure of the product gas. For low pressures, up to 150 psig, and industrial fuel gas applications, there are the chemical reaction processes such as amine and carbonate systems. At higher pressures, the physical absorption processes such as Rectisol^{R}, Purisol^{R}, and Selexol^{R} are used. The choice of the process is also dependent upon the desired purity of the product gas and the desired selectivity with respect to the concentrations of carbon dioxide and sulfides.

5.2 PROCESS ADVANTAGES

- Gasifier can accept all types of coal;
- No by-products, except sulfur, which require additional processing are produced;
- The absence of tars, oils, naphthas, and phenols in the raw gas simplifies control technology requirements;
- Gasifier can be started in 30 minutes and can be shut down instantly, and restarted in 10 minutes;
- Gasifier uses pulverized fuel, which eliminates rejection of fine coal particles;
- Gasifier has been reliably operated commercially for many years.

5.3 PROCESS LIMITATIONS

- Operation with steam plus air requires high air preheat and dilutes the product gas with nitrogen; thus, this mode of operation is not economical;
- Low operating pressure may be a disadvantage for transmission of the product gas or utilization in combined-cycle applications;
- Separation of high-temperature slag particles from the raw gas stream may be an operating problem.

5.4 PROJECT HISTORY

The Koppers-Totzek Process was developed commercially by Friedrich Totzek of Essen and the Koppers Company, Inc. of Pittsburgh in 1949 following the successful operation of a 36 TPD coal gasifier for the U.S. Bureau of Mines coal-to-oil demonstration plant at Louisiana, Missouri, in 1948.

There are approximately 20 Koppers-Totzek plants commercially operating around the world, none of which are in the U.S. These plants produce a carbon monoxide/hydrogen synthesis gas which is used in the synthesis of ammonia. Of all coal-based synthetic ammonia plants erected since 1945, more than 80 percent are based on Koppers-Totzek Gasifiers. A pressurized, single stage version of the Koppers-Totzek gasifier is currently being planned for construction in Hamburg, West Germany. The 150 TPD, 500 psi plant is scheduled for completion in 1977 followed by two to three years of testing. The project cost is estimated at $25 million. The project is a joint venture of Shell International Petroleum Company, and Krupp Koppers GmbH.

An interesting new development of Heinrich Koppers and Imperial Chemical Industries (I.C.I.), Billingham, U.K., is a combined carbon monoxide shift conversion and methanation unit. This unit's reactor uses a nickel catalyst which simultaneously promotes both the shift and methanation reactions. Testing of this reactor on a pilot scale has indicated that commercially acceptable lifetimes for the catalysts can be expected. This reactor will be installed in a Koppers-Totzek demonstration plant in Germany to produce 2.6 MMSCFD of SNG from a coal feed of 145 TPD.

In the U.S., Northern Illinois Gas Company and the State of Illinois are reportedly studying the Koppers-Totzek Process for application at their proposed 80 to 90 MMSCFD SNG demonstration plant to be completed in Illinois in the early 1980's.

5.5 ENVIRONMENTAL CONSIDERATIONS

The effluents summary is presented in Figure 5-2.

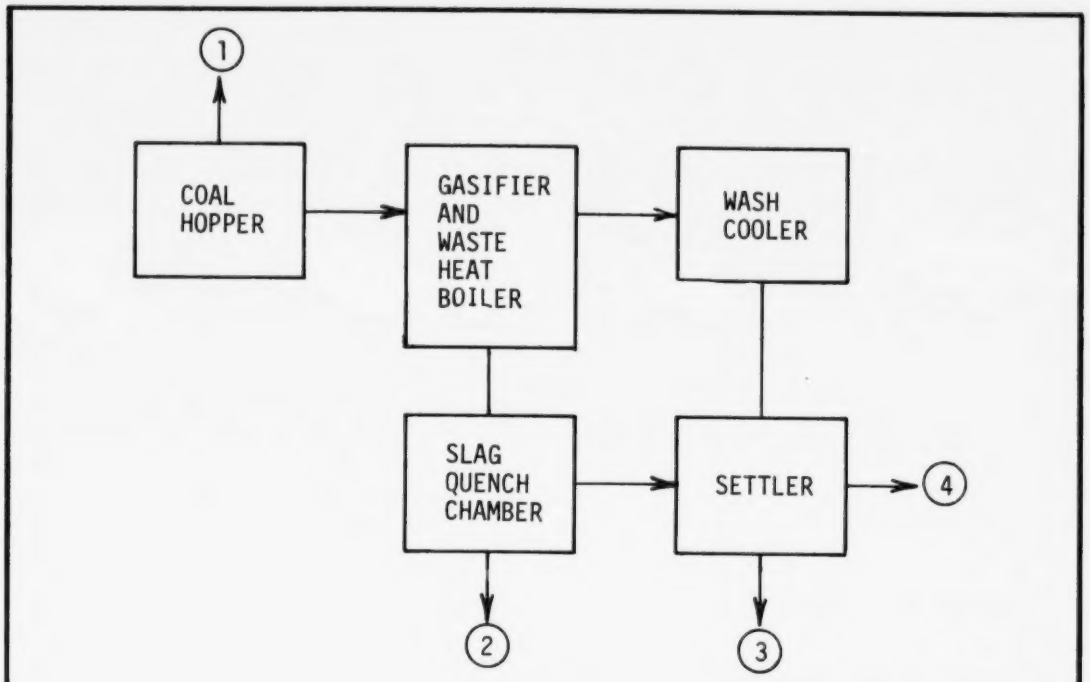

Figure 5-2
KOPPERS-TOTZEK PROCESS-EFFLUENTS SUMMARY

KOPPERS-TOTZEK PROCESS-EFFLUENTS SUMMARY FOR FIGURE 5-2

Stream #	Description
1	Nitrogen vent
2	Slag
3	Slag slurry
4	Condensate

Coal Hopper

Effluents to the Air - The nitrogen vent stream contains the nitrogen which is used to blanket the coal feed bins in order to prevent explosions of the fine coal particles. This stream will also contain entrained coal dust particulates, which can be removed with filters, cyclones, or scrubbers prior to venting the nitrogen to the atmosphere.

Liquid and Solid Effluents - No effluents are discharged.

Gasifier and Waste Heat Boiler

Effluents to the Air - No effluents are discharged.

Liquid and Solid Effluents - No effluents are discharged.

Slag Quench Chamber

Effluents to the Air - No effluents are discharged.

Liquid and Solid Effluents - The slag stream is composed of the larger slag particles formed in the gasifier which were heavy enough to fall to the bottom of the gasifier and into the slag quench tank. The slag particles will consist of the mineral matter present in the feed coal with 5 to 55 percent unreacted carbon. The slag

may also contain any components present in the slag quench water or in the raw gas. The exact composition of the slag is dependent on the composition of the feed coal and the gasifier operating conditions. The slag is a solid waste product which requires ultimate disposal. In some instances, the granular slag may be a salable by-product. Solid waste treatment processes can be used for slag disposal.

Settler

Effluents to the Air - No effluents are discharged.

Liquid and Solid Effluents - The process condensate and gas-quenching liquor stream is composed of the raw gas-scrubbing liquor plus raw gas condensate from waste heat boilers and indirect gas coolers. The overflow from the slag quench tank is also added to this stream. The slag particles which are removed from the raw gas stream in the wash cooler are separated from the process condensate in a settling tank, but some slag particles may be carried along in the process condensate stream. The other components in this stream are the constituents of raw gas which condense or dissolve in the quench liquor. The components most likely to be present in this stream are water, particulates, ammonia, hydrogen sulfide, and trace elements. Water pollution control processes can be used to remove these contaminants.

The slag slurry stream contains the smaller slag particles which are carried out of the gasifier in the raw gas. The slag particles are removed from the product gas stream in the direct quench wash cooler. The slag slurry is separated from the process condensate and gas-quenching liquor in a settling tank. The slag particles in this stream have approximately the same composition as the slag previously described. The slag slurry may also contain any of the components present in the raw gas, the process condensate and gas-quenching liquor, or the slag quench overflow. Solid waste treatment processes can be used for slag slurry disposal.

Wash Cooler

Effluents to the Air - No effluents are discharged.

Liquid and Solid Effluents - No effluents are discharged.

Auxiliary Facilities

A generalized discussion of auxiliary facilities common to most coal conversion plants is given in Appendix A.

Sulfur Balance

Sulfur recovery of about 97 percent can be achieved with three stages in "straight through" flow.

6. LURGI PROCESS FOR COAL GASIFICATION

The Lurgi Process is a commercially proven, high pressure dry ash gasification process for manufacturing fuel gas and other by-products from coal. The first gasification plant was developed in Germany in 1936.

6.1 PROCESS DESCRIPTION

The Lurgi Gasifier is a fixed-bed type gasifier with a vertical cylindrical construction. It is a high pressure gasifier, operating at 350 to 450 psig. The main gasifier shell is surrounded by a water jacket. Boiler feed water is circulated through the jacket to recover heat escaping from the gasifier shell. A coal lock hopper is mounted on top of the gasifier to feed the coal, while a motor-driven distributor is used to spread the incoming coal evenly over the coal bed. A motor-driven grate at the bottom of the gasifier is used to withdraw the ash formed. The ash drops into an ash lock hopper which is an integral part of the gasifier.

Coal received from the stockpiles is crushed and screened. The coal is transported to the gasifier lock hopper by a system of belt conveyors. Fines generated during the crushing and screening must be removed to maintain bed porosity. They are available for use in the plant or for export. Steam and oxygen are introduced at the bottom of the gasifier to effect the coal gasification reactions. The steam and oxygen are distributed into the coal bed through the rotating grate. The grate supports the coal bed and is continuously rotated to assure a constant and even withdrawal of the ash formed.

An alternative to oxygen is air, as shown in the bottom half of Figure 6-1. When gasifying with air, nitrogen in the air accompanies and dilutes the final product. Because nitrogen does not burn, the result is a gasifier product with a lower Btu value than one produced by the oxygenated Lurgi.

The following paragraphs describe the Lurgi Process as it operated with oxygen. Most of the steps which purify the gas to produce a higher quality product (shift reaction, acid gas removal, methanation), are not used with blown gasifiers. With the latter, the gasifier product gas, after minimal cleanup, goes directly to a power or steam plant.

As the steam and oxygen pass upward, four different zones in the coal bed can be identified by the prevailing reactions and temperatures. They are, from bottom to top, carbon combustion, gasification, devolatilization, and drying. As the coal descends through the bed, some volatile matter in the coal is first removed, and the remaining carbon is then gasified and combusted. The ash is withdrawn from the bottom of the gasifier into the lock hopper and eventually sent to disposal. Excess steam is added to the ash layer just above the grate to prevent slagging of the ash.

Raw gas formed in the gasifier leaves from the top and flows through a scrubber cooler, where it is washed by circulating gas liquor. The gas then passes through a waste heat boiler, where it is cooled and low pressure steam is generated. Condensate formed is subcooled and sent to a tar/liquor separator. Gas leaving the waste heat boiler is further cooled by three water-cooled heat exchangers in series. A part of the condensate recovered from this cooling is sent to the tar/liquor separator, and the remainder is sent to an oil/liquor separator.

Tar and the aqueous tar liquor are decanted in the tar/liquor separator. Similarly, tar oil and the aqueous oil liquor are decanted in the oil/liquor separator. The tar liquor and oil liquor are then combined and fed to a Phenosolvan^{R} unit and Chemie Linz-Lurgi (CLL) ammonia plant, where crude phenols and anhydrous ammonia are recovered.

Gas from the final cooler is desulfurized in an acid gas removal unit. By-product naphtha will

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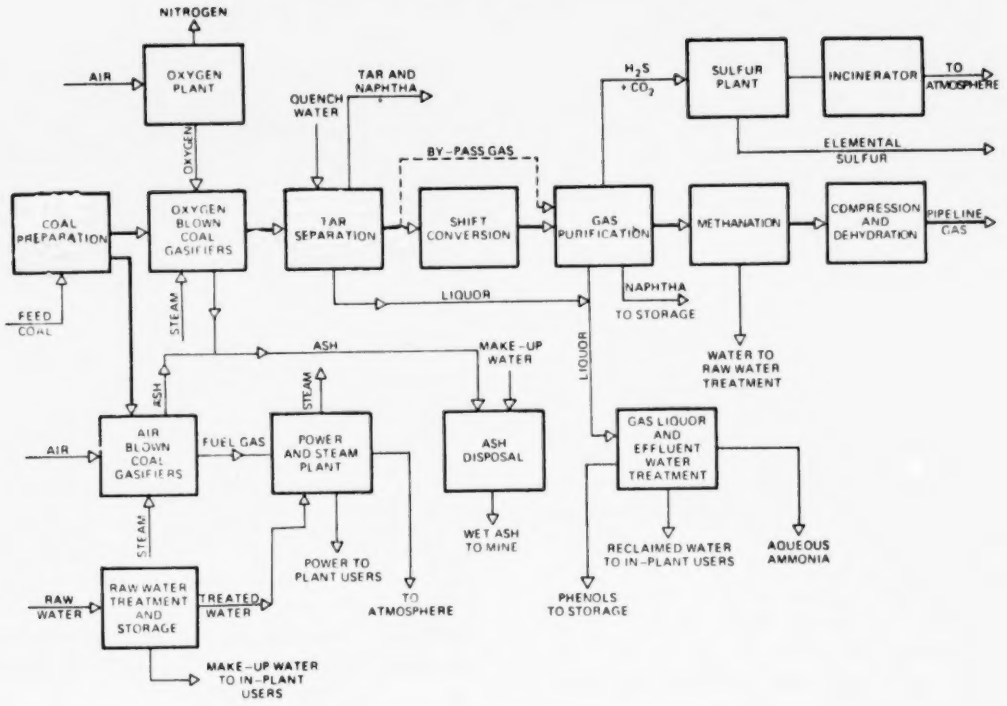

Figure 6-1
LURGI PROCESS SCHEMATIC

be recovered from the condensate collected in a cooling step prior to acid gas removal. The final product gas is a desulfurized medium-Btu gas.

6.2 PROCESS ADVANTAGES

- Slagging operation increases process efficiency and throughput rate over fixed-bed nonslagging operation;
- Lower steam consumption reduces the volume of liquid wastes requiring treatment;
- High-pressure operation favors the formation of methane in the gasifier and reduces gas transmission cost. High pressure is advantageous for utilization of the gas as a synthesis gas or in a combined cycle.

6.3 PROCESS LIMITATIONS

- Coals with low ash content or with a high percentage of refractory type ash may require addition of ash fluxing agents;
- By-products require additional processing for recovery;
- Process condensate and by-products require additional processing for environmental acceptability;
- Limited reactor size may necessitate use of multiple units in parallel for large installations.

6.4 PROJECT HISTORY

The first full-scale Lurgi coal gasification plant was constructed at Hirschfelde, Germany, in 1936.

Since then, 19 commercial plants have been installed worldwide. Various bench and pilot scale units have been erected to test various types of coal and alternate gasifier designs. In 1946, bench scale Lurgi Gasifiers of 4 inch, 6 inch, and 13.5 inch I.D. were built at the Central Experimental Station of the U.S. Bureau of Mines to test Alabama caking coals. Various other pilot plants have been built in Germany over the years. A 170 MW combined cycle plant utilizing the Lurgi pressure gasification system was tested in Lunen, Germany, in 1973. A commercial 800 MW plant is planned for start-up in 1980.

A number of American firms have announced plans to use the Lurgi Process in proposed SNG from coal plants. These include the El Paso Natural Gas Burnham project, ANG Coal Gasification Company's North Dakota project, Western Gasification Company (WESCO), Panhandle Eastern Natural Gas Pipeline, Northern Natural Gas/Cities Service Gas and a utility power gas project by Commonwealth Edison. The licensor in the U.S. is the American Lurgi Corporation, Hasbrouck Heights, New Jersey.

6.5 ENVIRONMENTAL CONSIDERATIONS

Since there are no Lurgi installations presently operating in the U.S., detailed information on operating procedures is often incomplete. Where operating procedures could affect the generation of effluents, it is necessary either to use engineering judgment in assuming a particular mode of operation or to consider more than one alternative procedure. EPA has proposed New Source Performance Standards for sulfur dioxide and non-methane hydrocarbon emissions from Lurgi high-Btu gasification processes. The effluents summary is given in Figure 6.2.

Coal preparation

Since coal preparation is common to all coal conversion plants, a general discussion is given in Appendix B.

Gasification

Effluents to the Air - There will be no direct discharge to the environment from the gasifier section which might suggest modifications to the actual process equipment. The most effective form of emission reduction would involve the improvement of "downstream" pollution control equipment.

Liquid and Solid Effluents - No effluents will be discharged.

Fuel gas production

The fuel gas burned to provide steam, electric power, and air compression for the plant will be obtained from a process train consisting of 10 air-blown Lurgi Gasifiers.

Effluents to the Air - All process streams and major waste streams will exit the area for processing and separation; none will be discharged to the environment at this point.

The steam-ash stream generated by the ash quench will initially be routed to a wet cyclone for removal of larger clinkers carried by the stream. The remaining material will be sent to a cooling-water condenser where stream will be condensed and returned to the ash transfer sluiceway. It is expected that almost all of the fine ash particles will remain in the condensate. The fate of the non-condensable gases is not known.

Liquid and Solid Effluents - No effluents will be discharged.

Feed lock hoppers

In the Lurgi Process, coal is fed to the gasifier in a cyclic operation using a pressurized hopper. The pressurizing gas must be vented each time the feed lock hopper is recharged. Normal charging frequency is 15 to 30 minutes.

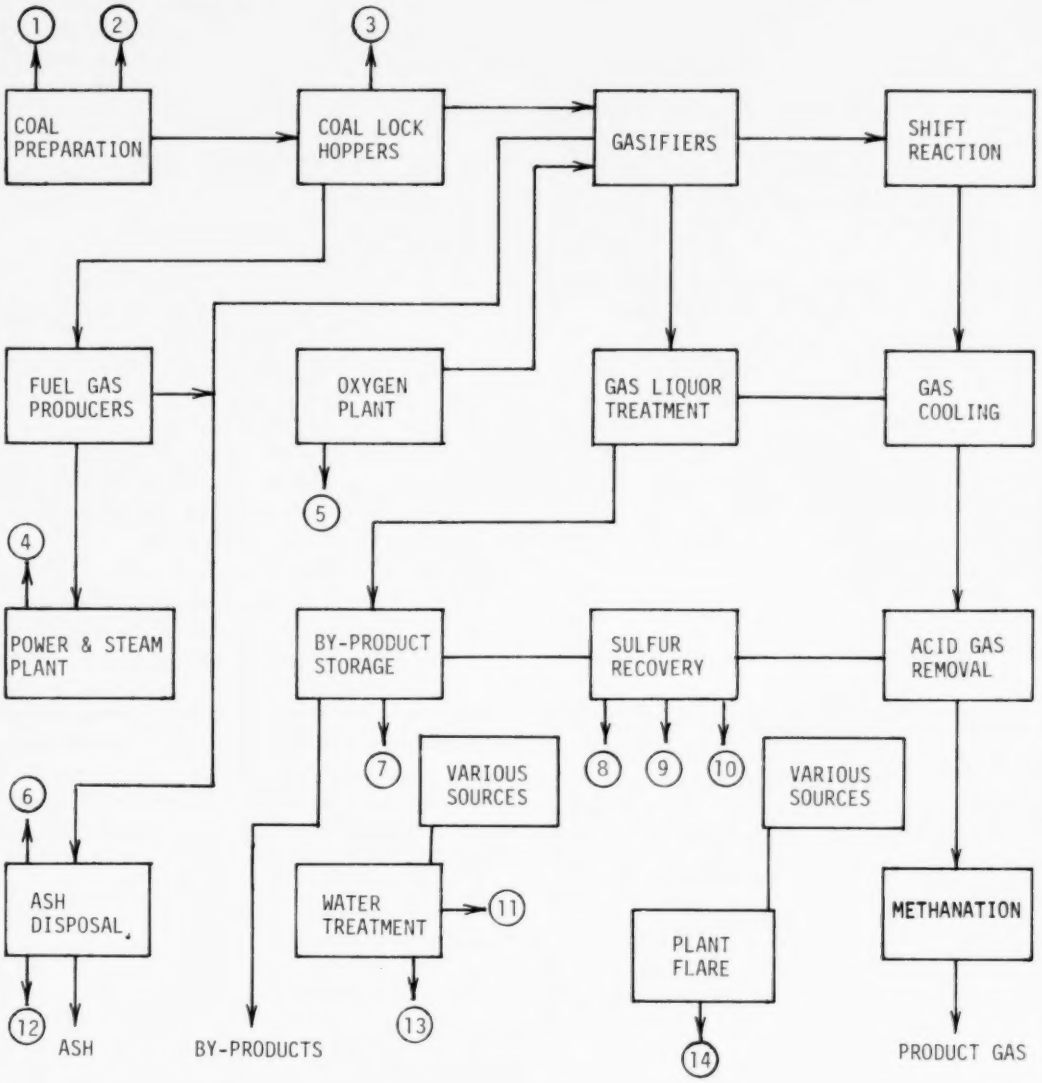

Figure 6-2
LURGI PROCESS-EFFLUENTS SUMMARY

LURGI PROCESS-EFFLUENTS SUMMARY FOR FIGURE 6-2

Stream#	Description
1	Fugitive dust
2	Coal refuse
3	Hopper vent
4	Exhaust stack
5	Nitrogen
6	Sluice vent
7	Tank vents
8	Stretford
9	Off-gas
10	Incinerator
11	Evaporation
12	Ash
13	Cooling loss
14	Flare gas

Effluents to the Air - Since the major control methods for feed lock hopper vent gases will consist of variations in process design which have not been tried, it is perhaps misleading to talk about proven methods. The discussion in this section, however, will address design variations which are believed to have no known technical problems. Several choices are available both for the source of the pressurizing gas and for the disposition of the gas when venting the lock hopper.

Among the choices which might be considered for a gas source are (1) raw crude gas, (2) clean crude gas, (3) product gas, (4) Rectisol^{R} vent gas, and (5) nitrogen from air plant. Any of these sources could provide sufficient quantities of gas chemically compatible with the coal in the lock hopper. Use of nitrogen or incinerator tail gas can probably be disqualified because it would introduce nitrogen into the product gas stream. The use of any slip-stream from the product gas flow, whether raw crude, clean crude, or final product gas, will result in some emission of this gas, even if most of it is recycled. On the other hand, if carbon dioxide from the Rectisol^{R} vent is used, this is a stream which is vented anyway, so total emissions may not be changed appreciably. All process equipment between the gasifier and the bleed point must be sized to handle the approximately 30 percent of lock gas which will pass into the gasifier with the coal feed. Therefore there is an economic incentive to locate the bleed point as close to the gasifier as possible. If Rectisol^{R} vent gas is used, then all equipment through the carbon dioxide absorption train must be oversized. Another economic factor is that bleeding from a high pressure stream rather than a low pressure stream will reduce compression costs.

In disposing of the feed lock hopper vent gases, at least four alternatives are available: (1) recycling, (2) venting to atmosphere, (3) use as plant fuel gas, and (4) incineration. Not all disposal options could be combined with every source option. For instance, if the source is carbon dioxide vent gas, it would obviously be impossible to dispose by burning as fuel. The ultimate choice must be based on considerations involving the rest of the plant design. For instance, if gas is being burned as a plant fuel then passing a slip-stream through the lock hopper before burning will not increase overall plant emissions. In this case, recycle compressors are not needed. If fuel gas, either crude or cleaned, is chosen to pressurize the lock hopper, there will be an economic incentive to recover the majority of the gas by either recycling or using as fuel, so that direct venting is unlikely. If carbon dioxide is used, then direct venting may be acceptable because this gas would be vented anyway. In the El Paso design, (250 billion Btu/day), the low-Btu lock hopper vent gas will be injected into the low pressure Stretford unit which processes acid gas from the Rectisol^{R} unit. This will automatically provide a clean fuel to fire the off-gas incinerator.

Although most of the feed lock hopper gas can be collected and disposed of by one of the options discussed, there will be a residuum of gas in the hopper when it is opened to receive a new coal charge (the hopper cannot be evacuated, it can only be bled down to some pressure slightly above atmospheric). During the coal transfer this residual gas will be displaced equal to the volume of coal being loaded.

Several plant designs have discussed the use of exhaust hoods and vent fans on the gasifier to prevent local escape of these gases. This type of control does not affect the net release to the environment unless the collected gases are then incinerated. The amount of gas escaping in this way should be only about 3 percent of the pressurant requirements. In the WESCO design (also a 250 billion Btu/day), it was stated that these gases would be collected by exhaust fans and vented from stacks, 150 to 300 feet high. The flow would be 99.5 percent air at a rate of 2,935 TPD. Estimated hydrogen sulfide concentraion was 5 to 10 ppm. If either clean crude gas or carbon dioxide from the Rectisol[R] vent is used, the hydrogen sulfide level should be much lower. There may be some hydrogen sulfide in the vent stream. The amount of any such blowback is impossible to estimate.

Localized control of vent gases from the ash lock quenching and ash-dumping operations can be accomplished also by hoods and exhaust fans. The exhaust fans for both the coal lock and the ash lock can be equipped with wet cyclone scrubbers to reduce particulate concentrations before being vented from stacks. The WESCO Environmental Impact Statement (EIS) contained an estimate of particulate emissions from the lock exhaust fans with cyclone scrubbers which amounted to only 0.1 lb/hr for the the coal lock and 0.2 lb/hr for the ash lock.

Most of the control methods discussed are actually process modifications rather than end-of-pipe methods of treatment. Additional modifications which could be developed would include the feeding of the exhaust vent streams to the intake air for air-blown gasifiers, gas turbines, or steam boilers. Since the potential emissions involved are so small to begin with, there is little incentive to spend effort in investigating such modifications.

It is apparent that total venting of lock hopper gases could be a significant source of emissions if the gas is obtained from an internal process stream. All designs utilizing such internal streams should require either recycling or routing to a pollution control unit.

Liquid and Solid Effluents - No effluents will be discharged.

Ash Lock Hoppers

Ash will be discharged from the bottom of the gasifier through a lock hopper which must be vented. Ash hopper discharge cycles will take about 20 minutes.

Effluents to the Air - Ash will be discharged from the bottom of the gasifier in a sequence of operations similar to that for the feed lock hopper. First the top ash lock cone valve is closed, isolating the ash lock chamber. High pressure gases in the ash lock at this point are mainly steam. The chamber is vented to a close-coupled direct contact condenser, where the steam is condensed with a water spray. The bottom ash lock valve is then opened, and the ash falls out. After the ash is dumped, both cone valves are closed, and the ash lock chamber is repressurized with steam. The top ash lock valve is opened, and ash flow from the producer is re-established.

As in the case of the coal feed lock hopper, it is possible that a different operating procedure could be used in which the ash lock chamber is not repressurized before reopening the valve to the gasifier vessel. In that case gases from the gasifier would flow into the ash lock hopper. Venting of the ash hopper on the next cycle could then result in the emission of some of these gasifier gases.

Liquid and Solid Effluents - Several variations are possible in handling the ash as it drops from the ash lock chamber. In one design, the ash drops into circulating "mud water" in an ash quench chamber directly below the ash lock. In the El Paso design the ash will apparently be discharged dry at about 360°F into a sluice launder where it will be completely quenched and flushed away by a water stream. Since the gasifier bottom temperature will be around 900°F, it is assumed that partial cooling is accomplished by water spray before dropping into the sluice launder. Steam generated in the quenching will be condensed either in the direct

contact condenser coupled to the ash lock valve or in a condensing vessel above the sluice launder. To cool the ash from 900°F to 360°F, assuming a specific heat of 0.2, would require approximately 49,000 lbs of water per hour.

During the ash quenching, large amounts of ash dust will be generated and entrained in the steam passing to the condensers. Some non-condensable gases may be generated also by reaction between unburned char and steam or by thermal cracking of organic contaminants in the quenching water. The water spray in the condenser will provide a wet scrubbing action to remove most of the ash dust from the non-condensable gas which must be vented. Estimated flow rate is 477,000 lb/hr as ash. Approximately 64,000 lb/hr of water will be flashed to steam in the two-step quench process. No information is available for estimating the amount of non-condensable gases formed or the amount of particulates carried by this stream.

Shift Conversion

Effluents to the Air - Fugitive air emissions are inevitable in any process which contains fittings, valves, flanges, etc. The high pressure encountered in the shift reaction section tends to increase the likelihood of having fugitive emissions. While fugitive emissions cannot be completely eliminated, the use of best available technology coupled with good maintenance practices will help to minimize these emissions.

The shifted gas will be processed in other sections to remove tars, tar oils, phenols, ammonia, and sulfur compounds. These processing areas will provide adequate control for this stream.

Liquid and Solid Effluents - The process condensate stream will be recycled to the gas production section where it will be combined with other condensate streams for use as gasifier effluents quench liquor.

The blowdown stream from the waste heat boiler will be used as makeup water to the plant cooling system. Since the boiler will operate at a relatively low number of cycles of concentration, the dissolved solids content of the blowdown stream will be relatively low and will not represent an environmental problem.

The control methods for spent catalyst are not fully developed at this time because of the lack of knowledge about its makeup. If the catalyst does not have value sufficient to justify regeneration, the most likely disposal method will be as landfill. However, if the catalyst is sufficiently toxic to warrant more elaborate treatment, some of the methods employed for nuclear or hazardous solid waste disposal could be adopted.

Gas Cooling

The gas-cooling section of the Lurgi Coal Gasification Process takes shift-reactor effluent gas and crude gas from the gas production section and cools them in separate but similar cooling trains. The system of coolers is designed to recover a significant portion of the useful energy content of the gas streams.

The gas-cooling section will not discharge any effluent stream, with the exception of fugitive emissions, directly to the environment. Instead, these streams will be directed to other processing areas for treatment or reuse.

Effluents to the Air - Fugitive air emissions are inevitable in any process which contains fittings, valves, flanges, etc. The high pressures encountered in the gas-cooling section tend to increase the likelihood of having fugitive emissions. While fugitive emissions cannot be completely eliminated, the use of best available technology, such as mechanical seals on pumps, and good maintenance practices can help to minimize these emissions.

Liquid and Solid Effluents - The blowdown streams from the waste heat boilers will be collected and used as makeup water to the pilot cooling system. Since the boilers will operate at a relatively low number of cycles of concentration, the dissolved solids content of these blowdown streams will be relatively

low and will not constitute an environmental problem.

Acid Gas Removal

In the gas purification section the Rectisol I^R Process will be used to remove acid gases such as carbon dioxide, hydrogen sulfide, carbonyl sulfide, carbon sulfide, mercaptans, etc., from inlet gas streams by physical absorption of these acid gases in a methanol solvent.

Effluents to the Air - Fugitive air emissions from the Rectisol I^R acid gas removal process arise from leaks around pump seals, valves, flanges, etc. High pressures in this process enhance fugitive leaks from equipment. The compositions of these fugitive emissions would be a mixture of any of the various components found in the process streams.

The gas streams generated in the prewash flash and in the main flash regenerators will comprise primarily carbon dioxide, about 98 percent by volume, with smaller amounts of carbon monoxide, hydrogen, methane, ethylene, ethane, hydrogen sulfide, and carbonyl sulfide. The amounts of these compounds present will depend upon the composition of the raw gas from the gasifier and the operating parameters of the Rectisol I^R Process, such as absorber temperature and pressure. The presence of sulfur compounds necessitates further treatment of this stream. The method will depend upon several factors, including the amounts and types of sulfur compounds present.

The off-gases from the hot regenerator will comprise carbon dioxide, carbon monoxide, hydrogen, methane, hydrogen sulfide, and carbonyl sulfide. The concentration of hydrogen sulfide will be higher in this stream, about 13 percent by volume, than in the flash gases. The concentration of the other components will depend primarily upon operating parameters such as the flash regeneration pressure. This stream may also contain substantial amounts of methanol, depending upon the product gas (overhead) temperature and the pressure of the hot regenerator. This gas stream is sent to the sulfur recovery section.

The gases released during the first stage of flash regeneration will comprise carbon dioxide, carbon monoxide, methane, ethylene, ethane, hydrogen, and some nitrogen and argon. Since this stream will contain high concentrations of desirable gases, it will be recombined with the cooling section product gas upstream of the acid gas removal section.

The product gas exiting the Rectisol^R Process will comprise carbon monoxide, hydrogen, methane, ethylene, ethane, and, depending upon the required product specification, possibly small enough amounts of carbon dioxide, hydrogen sulfide, and carbonyl sulfide and organic sulfur. This gas stream will be sent to the methanation section for conversion into substitute natural gas (SNG).

The by-product naphtha stream will comprise C_6-C_8 (predominantly aromatic) hydrocarbons removed in the prewash. This stream, which may also contain small amounts of dissolved acid gases, ammonia, and phenols, will be sent to a by-product storage facility.

Liquid and Solid Effluents - The process condensate, from the methanol/water still, will comprise primarily the water in the feed gas and the water used in the naphtha extraction operation. This stream will be sent to the wastewater treatment section.

Methanation

The only important stream leaving this area will be the 629 gpm of water produced in methanation.

Effluents to the Air - This water stream will contain a total of 69 lbs/hr of methane and carbon dioxide. Release of this gas to the atmosphere should not cause any problem.

Catalyst dust can be controlled by dumping the catalyst into water and using a bag filter at vent locations. In some catalyst systems, it may be possible to regenerate catalyst without removing it. In that case, absorbed impurities will be released to the atmosphere. However,

the amount and frequency of discharge of these pollutants are going to be very small.

Start-up and shut-down will require special precautions so the carbon monoxide does not come in contact with nickel below 300°F, thus avoiding the formation of highly toxic nickel carbonyl. During shut-down, vent gases will either be recompressed for later use in process or be sent to the fuel-burning section of the plant to be used as fuel.

To minimize leakage, a tight system must be specified and then maintained properly. Pump and compressor seals are potential sources of leakage and need special attention.

Liquid and Solid Effluents - After the atmosphere strips methane and carbon dioxide from the main water stream, the clean water can be used as soft water in the plant.

Two other small streams of water, about 1 gpm each, containing traces of methane and glycol can be dumped into the ash system.

Gas Liquor Treatment

The streams leaving the main Lurgi Gasifier and the fuel gas gasifier will be produced at a rate of 100 TPH. The chemicals contained therein can be treated or recovered and subsequently utilized. Some of the streams will require primary and secondary treatment. Primary treatment will control or recover pollutants; it will not be required in the production of SNG. Secondary treatment will control pollutants resulting from the primary treatment.

Effluents to the Air - Flashed gases containing mostly carbon dioxide, hydrogen sulfide, water, and small amounts of tar products will be sent to the sulfur recovery section after having been scrubbed with water.

Liquid and Solid Effluents - Gas liquors will be sent to phenol extraction and then to ammonia recovery.

Tar and oil streams will be sent to the storage area.

Auxiliary Facilities

A generalized discussion of auxiliary facilities common to most coal conversion plants is given in Appendix A.

Sulfur Balance

Sulfur balance is given in Table 6-1.

Table 6-1
LURGI PROCESS SULFUR BALANCE

	percent
Sulfur product	89.4
Tar and tar oil naphtha	1.7
Naphtha	0.1
Ash	1.4
Incineration	5.8
Power plant	1.6
	100.0

7. SLAGGING/LURGI GASIFIER

The Slagging/Lurgi Gasifier is being developed by the British Gas Corporation, London, England, and the Lurgi Mineralö technik GmbH, Frankfurt, Germany. The process function is high pressure coal gasification in a gravitating bed by injection of steam plus oxygen with countercurrent gas/solid flow. The Slagging/Lurgi Gasifier Process offers higher operating capacity than does the "dry bottom" version of the Lurgi Process. Development work is currently being conducted at the Westfield Development Centre, Westfield, Scotland. A demonstration plant in Westfield has been in operation since 1976.

In the U.S., a test plant in slagging, fixed-bed gasification is being operated by ERDA's Grand Forks Research Center, Grand Forks, North Dakota. ERDA has also awarded $24 million to Continental Oil Company, Stamford, Connecticut, for design of a high-Btu gas plant in Noble County, Ohio.

7.1 PROCESS DESCRIPTION

Fixed-bed gasification, as exemplified by the Lurgi Process, is basically a thermally efficient system. The feed coal is heated by heat exchange with the exit product gases and vapors which are cooled and leave the system at moderate temperatures, see Figure 7-1. Similarly, the entering gasifying agents (steam and oxygen) are preheated by heat exchange with the ash which, on leaving the combustion zone stripped of carbon, is cooled from the high temperature which prevails in the gasification zone. Essentially, 90 percent of the potential heat in the coal supplied leaves as potential heat in the gas and liquid products of gasification.

The chief differences between the "dry bottom" Lurgi and the slagging gasifier are higher operating temperatures and operation under slagging conditions.

7.2 PROCESS ADVANTAGES

- Process efficiency: Slagging operation increases process efficiency and throughput rate (by two to four times) over fixed-bed nonslagging operation;
- Steam consumption/conversion: Operation at slagging temperatures reduces steam consumption and increases steam conversion;
- Environmental considerations: Lower steam consumption reduces the volume of liquid wastes requiring treatment;
- Operating pressure: High pressure operation favors the formation of methane in the gasifier and reduces gas transmission cost. High pressure is advantageous for utilization of the gas as a synthesis gas or in a combined cycle;
- Fuel size: Coal fines may be injected into the gasifier through the steam/oxygen tuyeres;
- Reactor size: Small reactor size may be advantageous for small-scale industrial applications.

7.3 PROCESS LIMITATIONS

- Coal type: Coals with low ash content or with a high percentage of refractory-type ash may require addition of ash-fluxing agents;
- Gasification media: Operation with steam plus air will not provide hot enough temperatures for slagging operation;
- By-products: By-products require additional processing for recovery;
- Environmental considerations: Process condensate and by-products require additional processing for environmental acceptability;
- Reactor size: Limited reactor size may necessitate use of multiple units in parallel for large installations;
- Development status: Gasifier has only been operated on a pilot-plant scale.

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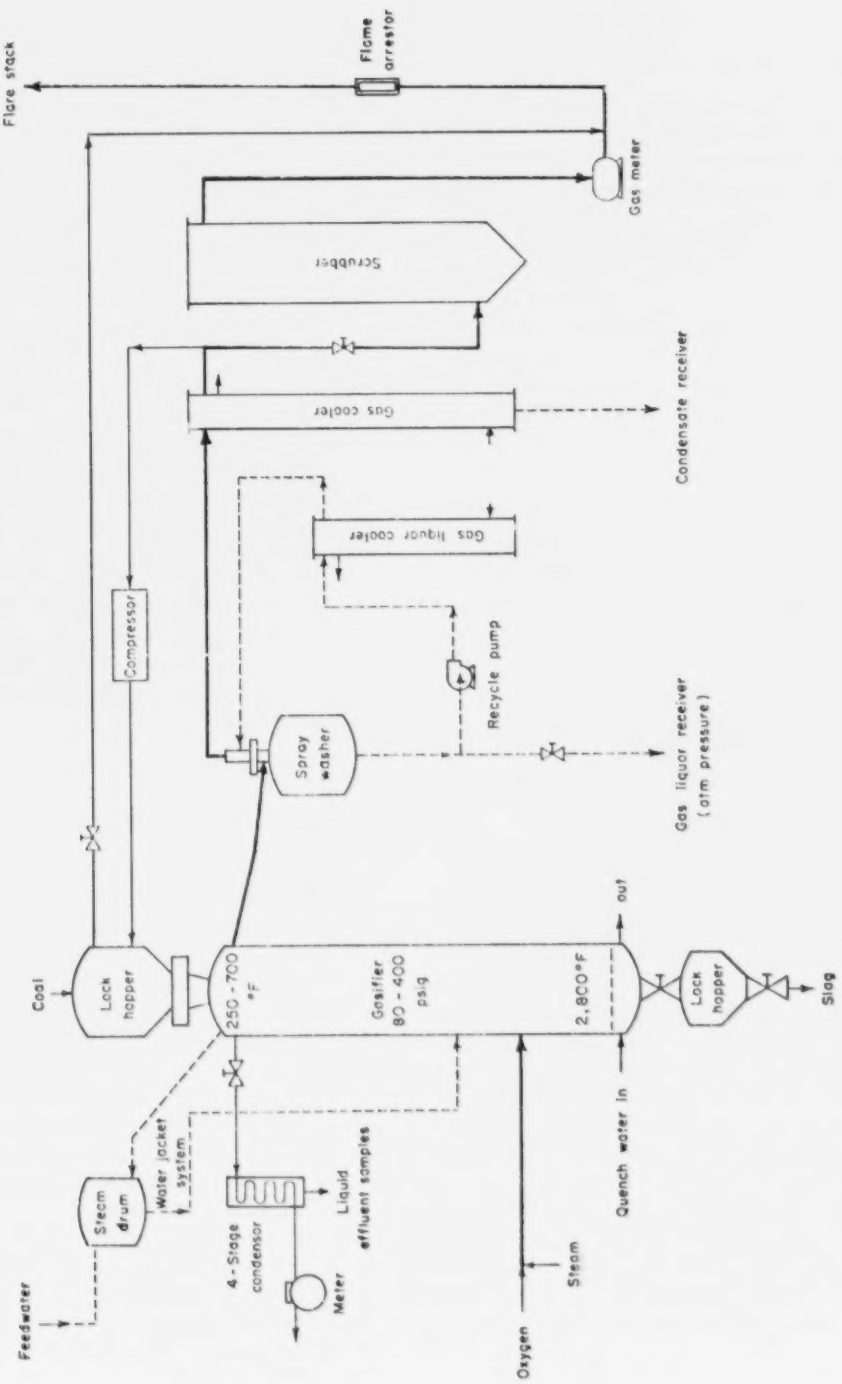

Figure 7-1
GRAND FORKS SLAGGING GASIFICATION PILOT PLANT PROCESS SCHEMATIC

7.4 PROJECT HISTORY

A pilot slagging gasifier was developed at the British Gas Midlands Research Station (MRS) at Solihull, England, during the period 1955-1964 and followed a detailed study of the reactions occurring at a pilot Lurgi-type gasifier. All this work is well documented. The work was suspended at a stage at which further useful development could only be continued on a larger scale under conditions which allowed continuous operation of several months rather than several days duration. At that time, in 1963-1964, Westfield had been mentioned as a possible site but any chance of following this up was overtaken by the discovery of natural gas under the North Sea. Research and development programs on coal were terminated and eventually the MRS pilot plant was dismantled.

The gasifier was still of interest in the U.S. because it is a fixed-bed type and represented continued development of the Lurgi Gasifier. The Westfield Lurgi gasification plant of the British Gas Corporation has been used by a consortium of U.S. gas, oil, and pipeline companies led by the Continental Oil Company. Their purpose was to demonstrate the production of SNG from coal-based synthesis gas. The plant was also used by the AGA to test the gasification of a series of U.S. coals in the Lurgi Gasifier. The two programs were successfully completed.

On the initiative of the Continental Oil Company and with the full support of British Gas, who recognized the potential international value of the Westfield plant as a gasification development and demonstration center, a program for the development of the slagging gasifier to commercial status was put up for sponsorship. As a result, a project to convert one of the Westfield Gasifiers to slagging operation and undertake its development according to a three-year program was initiated under the sponsorship of the 15 American companies listed in Table 7-1. In addition, by agreements signed with British Gas, the Lurgi Company of Frankfurt joined the project and is collaborating fully in the development work. A gasifier incorporating British Gas and Lurgi technology will be licensed by British Gas on behalf of the sponsors who will receive a share in the license fees.

Table 7-1
UNITED STATES COMPANIES SPONSORING THE WESTFIELD SLAGGING GASIFIER PROJECT

Cities Service Gas Company/Northern Natural Gas
Continental Oil
Electric Power Research Institute
El Paso Natural Gas
Gulf Energy and Minerals
Michigan Wisconsin Pipe Line
Natural Gas Pipeline
Panhandle Eastern Pipe Line
Southern Natural Gas
Standard Oil of Indiana
Sun Oil
Tennessee Gas Pipeline
Texas Eastern Transmission
Transcontinental Gas Pipeline

This new gasifier will complement the "dry bottom" Lurgi Gasifier by making the less reactive coal with low fusion point ash suitable for fixed-bed steam and oxygen gasification at high pressure. The standard Lurgi Gasifier is better suited to handle the high fusion point, high ash content, high reactivity coals which can be gasified at high load with low steam-oxygen ration.

Coals with refractory ash present in quantities in excess of 15 percent, particularly if accompanied by high moisture contents, are less suitable for slagging conditions. While the advantages of high output from a slagging gasifier remain unimpaired and refractory ash can be accommodated by the addition of fluxes, high ash, high moisture coals can lead to problems in the top of a slagging gasifier. The top of the gasifier may be insufficient in heat to drive off the moisture and distill the tar. Much product gas with low heat capacity is present as a consequence of the inherent high gasification efficiency of slagging operation. These problems can be overcome by injecting fuel (such as coal fines or tar, etc.) at the tuyeres but at some cost in lower efficiency and higher oxygen consumption.

Highly suited to slagging operation are coals of low or high reactivity if they have the following properties: either less refractory ash or refractory ash present in quantities less than about 15 percent by weight; and moisture contents not in excess of about 20 percent by weight. Full benefit can be derived from increased gasifier output, low steam consumption, low aqueous liquor production, and higher gasification efficiency leading to lower gas production costs. Thus, one sees a future of both gasifiers complementing each other.

The Grand Forks Energy Research Center operation has as its goals the establishment of a data base and investigation of processes for treating effluents. The program began in April 1977 and will run two years.

ERDA's $24 million award to Continental Oil Company for design of a facility in Noble County, Ohio, will also involve a consortium of pipeline companies, monitoring the 22-month design phase. The consortium will then decide on participation in construction and operating costs.

7.5 ENVIRONMENTAL CONSIDERATIONS

Since the Slagging/Lurgi Gasifier closely resembles "dry bottom" Lurgis, the only unique characteristic is slag removal and treatment. The actual operation of the slag tap is proprietary. The effluents summary is presented in Figure 7-2.

Coal Preparation

Since coal preparation is common to all coal conversion plants, a general discussion is given in Appendix B.

Coal Lock Hopper

Effluents to the Air - The composition of the coal lock gas stream will be determined by the mode of pressurizing the coal lock. Various operating procedures and sources of pressurizing could be used. Prior to dumping the coal from the lock into the gasifier, the lock may be pressurized to the gasifier operating pressure with a stream of cooled raw gas or with a vent stream from an acid gas removal process. If the pressurizing gas is added continuously as the coal dumps into the gasifier, the gas remaining in the lock will have approximately the same composition as the pressurizing gas. If no gas is added as the coal is dumped, raw gas from the gasifier will back-flow into the lock as the coal falls into the gasifier, and the gas remaining in the lock will be composed of pressurizing gas and raw gas from the gasifier. If no pressurizing gas is used, the lock will fill with raw gas as the coal is dumped into the gasifier, and the gas remaining in the lock will be composed of raw gas. For any of these cases, as raw gases pass countercurrently through the incoming coal and into the lock, some tars, oils, water and other constituents of the raw gas may condense or be adsorbed on the coal feed. In addition to the components in the raw gas and the lock-filling gases, the coal lock gas stream may also contain entrained coal fines. In order to prevent the release of these contaminants to the atmosphere, this stream may be recycled to the raw gas stream, or it may be incinerated in a flare or boiler. If gaseous contaminants in this stream are relatively low in concentration, the stream may be passed through wet cyclones to remove particulates, and then vented to the atmosphere. The gas which remains in the lock after depressurization will be displaced by the incoming coal charge. This gas can be controlled by the same methods described previously, but hoods and vent fans would be required to collect the gas.

Liquid and Solid Effluents - No effluents will be discharged.

Gasifier

Effluents to the Air - No effluents will be discharged.

Liquid and Solid Effluents - No effluents will be discharged.

Slag Lock Hopper

Effluents to the Air - No effluents will be discharged.

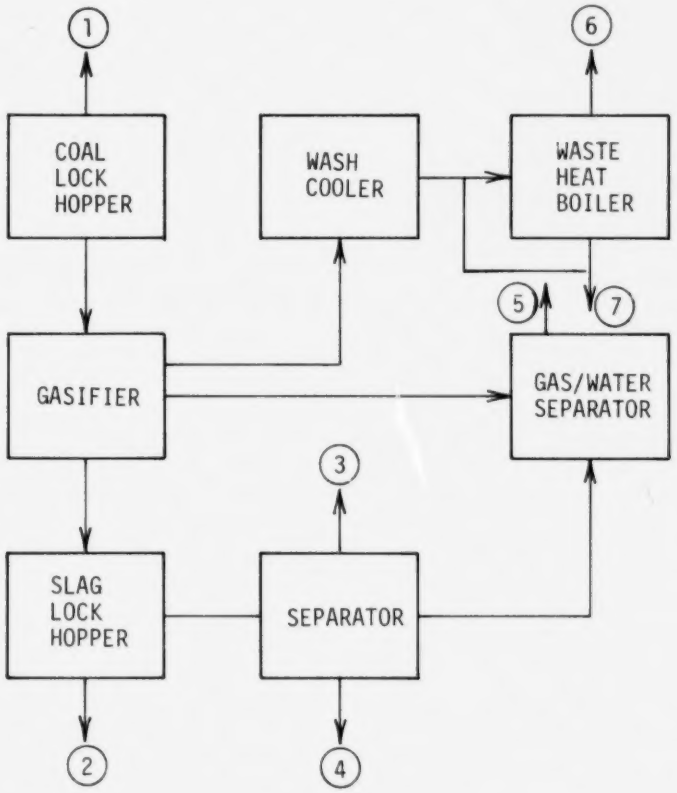

Figure 7-2

SLAGGING/LURGI PROCESS-EFFLUENTS SUMMARY

SLAGGING/LURGI PROCESS-EFFLUENTS SUMMARY FOR FIGURE 7-2

Stream #	Description
1	Lock hopper vent gas
2	Slag and water
3	Vent gas
4	Blowdown
5	Vent gas
6	Steam
7	Condensate

Liquid and Solid Effluents - The slag slurry contains slag particles and slag quench water. The slag quench water in the slurry will have the same composition as the slag quench blowdown. The slag is composed of the mineral matter in the feed coal with approximately 1 percent unreacted carbon plus any ash-fluxing agents added to the feed coal. The exact composition of the slag is dependent on the composition of the feed coal and fluxing agents (if used) and the gasifier operating conditions. Suspended solids removal processes can be used to dewater the slag slurry. The recovered water could be recycled to the process con-

densate and the gas-quenching liquor. The dewatered slag or slag slurry is a solid waste product which requires ultimate disposal using known techniques.

Separator

Effluents to the Air - The slag lock gas stream is created when the slag lock is depressurized in order to discharge the slag slurry. This stream may contain components in the raw gas from the gasifier which have dissolved in the slag quench water, steam, entrained slag particles, and any volatile components in the slag quench makeup water. Depending on the composition of the slag lock gas, it may first be passed through a cyclone to remove particulates and then vented to the atmosphere, or it may be incinerated in a flare or boiler.

Liquid and Solid Effluents - The slag quench blowdown stream will be composed of the slag quench water which is removed from the slag lock prior to removal of the slag slurry. This stream will also contain condensate from the slag quench vent gas/liquor separator. The slag quench blowdown may contain any of the components present in the raw gas from the gasifier or in the quench water makeup. This stream may also contain entrained slag particles. The concentrations of contaminants in this stream will determine the control technology used. It may also be sent to disposal in evaporation ponds which will result in emissions to the atmosphere of all volatile components in the stream. This stream may also be treated by water pollution processes.

Gas/Water Separator

Effluents to the Air - The composition of the slag quench vent gas stream will be determined by the mode of operation of the slag tap. If the slag is tapped intermittently by preventing slag flow with a slag burner, the slag quench vent stream will be created when slag is removed from the gasifier by swinging the slag burner aside and by opening the slag quench vent to create a positive pressure differential across the slag tap hole. For this case, the slag quench vent stream will be composed of combustion products, raw gas from the gasifier, steam, entrained slag particles, and any volatile components in the slag quench makeup water. This gas stream may first be passed through a cyclone to remove particulates, or it may be incinerated directly in a flare or boiler. If the slag is tapped continuously, a slag quench vent stream will not be present.

Liquid and Solid Effluents - No effluents will be discharged.

Wash Cooler

Effluents to the Air - No effluents will be discharged.

Liquid and Solid Effluents - The raw gas scrubbing liquor is combined with raw gas condensate from the waste heat boiler.

Waste Heat Boiler

Effluents to the Air - The only effluent released to the air is steam.

Liquid and Solid Effluents - The process condensate and the gas quenching liquor will be composed of water plus the constituents of the raw gas which condense or dissolve in the quench water. The components most likely to be present in this stream are water, tar, tar oil, naphthas, crude phenols, coal fines and ash, ammonia, hydrogen sulfide, organic sulfur compounds, cyanide, thiocyanates, and trace elements. The amounts of these components will depend on the raw gas composition and the gas quenching and cooling processes used. Water pollution control processes exist that can be used to remove these contaminants.

Auxiliary Facilities

A generalized discussion of auxiliary facilities common to most coal conversion plants is given in Appendix A.

Sulfur Balance

Sulfur balance data are not available.

8. SYNTHANE PROCESS

The Synthane Process, developed by the U.S. Bureau of Mines, is being tested on a pilot plant scale by ERDA. The government-owned plant is being operated by the Lummus Company and is located in Allegheny County, Pennsylvania. Funding for the project is set at $24 million.

8.1 PROCESS DESCRIPTION

A key feature of the Synthane Process is that pretreatment of caking coals is integrated with gasification. Another feature is that gas with a high methane content is produced directly. A schematic of the Synthane Process is provided in Figure 8-1. There are four major steps in the process: (1) coal pretreatment, (2) coal gasification, (3) shift conversion and purification, and (4) methanation.

Coal, crushed to -20-mesh, is dried, pressurized to approximately 70 atm, and transferred into the fluidized-bed pretreater by means of high pressure steam and oxygen. Pretreament provides a mild oxidation of the coal particle surface so that caking coals will not agglomerate in the gasifier. The coal overflows from the pretreater into the top of the fluidized-bed gasifier about 10 feet above the bed level, falls through hot gases rising from the fluidized-bed, and is devolatilized. This devolatilization contributes significantly to the methane yield. Steam and oxygen enter the gasifier just below the fluidizing gas distributor. The gasification reaction occurs within the fluidized-bed. Unreacted char flows downward into a bed fluidized with steam and water sprays and is removed through lock hoppers. This char can then be burned to produce process steam. This product gas, containing methane, hydrogen, carbon monoxide, carbon dioxide, ethane, and impurities, is passed through a venturi scrubber and a water scrubber to remove carryover ash, char, and tars.

The concentration of hydrogen and carbon monoxide in the gas is then adjusted to a 3:1 mole ratio in a shift converter. The acid gases are adsorbed in a hot potassium carbonate scrubber. Carbon dioxide is reduced to 2 percent volume, and sulfur is reduced to 40 ppm. Regeneration of the potassium carbonate solution produces a hydrogen sulfide-rich gas which is converted to elemental sulfur by the Stretford Process. The remaining traces of sulfur in the product gas are removed by passing the gas through activated charcoal. The purified gas must then be reacted catalytically to convert the hydrogen and carbon monoxide to methane.

8.2 PROCESS ADVANTAGES

- Caking coals can be used directly as can a wide range of other coals, including lignite;
- Hydrocarbons released during pretreatment are used within the system, thereby maximizing the efficiency of coal conversion to gas;
- More than half of the methane is produced directly in the gasifier. By maximizing methane production in the gasifier, oxygen requirements are reduced. Therefore, the investment for an oxygen plant is lower, and the sizes of all process vessels downstream from the gasifier are reduced by 30 to 50 percent, compared to processes in which the raw gas from the gasifier contains little or no methane. The process flow system and equipment are relatively simple.

8.3 PROCESS LIMITATIONS

- Char is produced which must be utilized for steam production in an environmentally acceptable manner;
- Some tars and oils are produced which must be disposed of or utilized;
- More economical feeding methods than the currently used lock hopper must be developed.

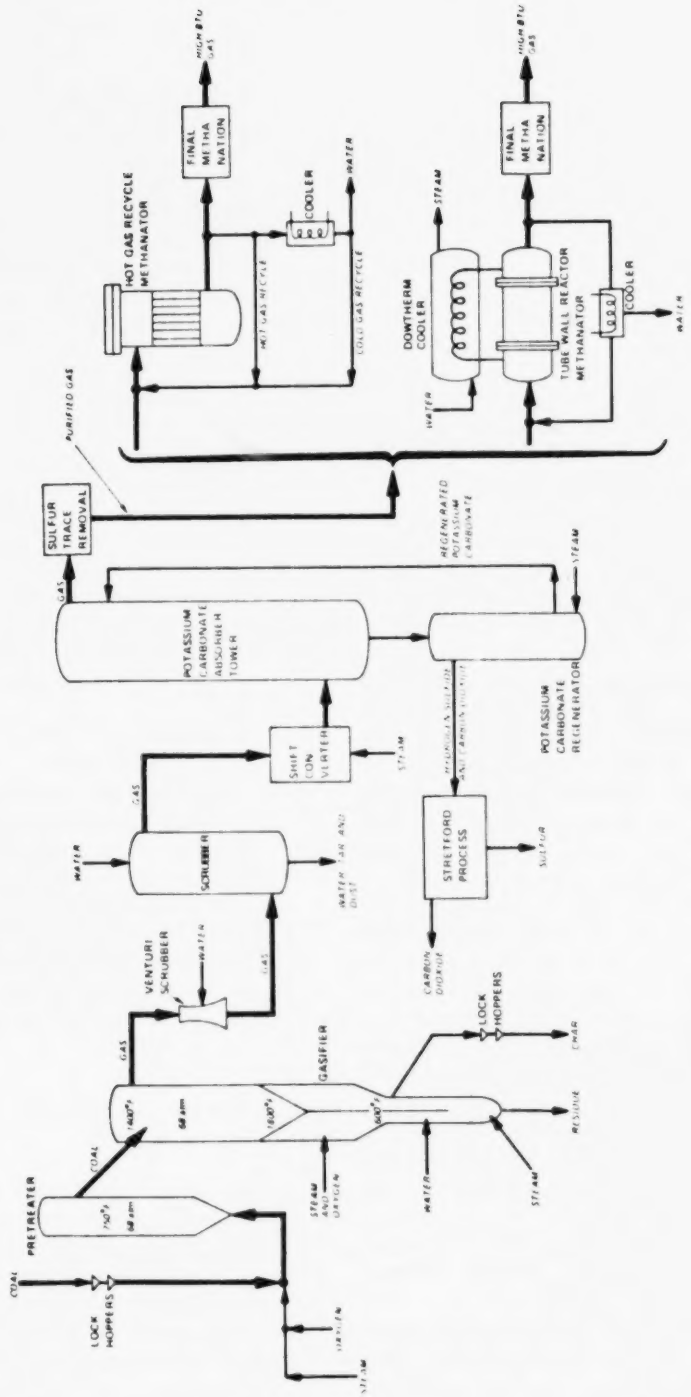

Figure 8-1
SYNTHANE PROCESS SCHEMATIC

8.4 PROJECT HISTORY

The Synthane Process was developed by the U.S. Bureau of Mines at the Pittsburgh Energy Research Center, Bruceton, Pennsylvania. Development work started with scattered research in several areas. In 1961, work was started on methods of pretreating caking coals in fluidized beds. A preliminary design contract was awarded to M. W. Kellogg Company in August 1970 to determine if the data were sufficiently complete to proceed with design of the pilot plant. The contract was extended for additional gasifier tests and further evaluation of the Synthane project. Based on the results of the gasifier tests and the evaluation, the U.S. Bureau of Mines concluded that the process was feasible and the design could begin.

In June of 1971, a contract was awarded to Lummus for obtaining process information and designing the pilot plant. The contract was modified several times to increase its scope to include rating and sizing heat exchangers, purchasing equipment, preparing a bid package, preparing a final report, additional engineering, inspecting, and control monitoring. Rust Engineering was awarded a contract to construct a pilot plant from design information obtained by Lummus.

Construction of the Synthane pilot plant was completed in March of 1975, and all areas and systems operations were transferred from the construction contractor to ERDA. Through 1975 work concentrated on installation of auxiliary equipment and the repair and modification of the plant due to faulty equipment and design changes. During the first quarter of 1976 these repairs and changes were made and initial testing began. A number of runs were made; however, most of them were of relatively short duration. At present, operational and equipment problems continue to plague the pilot plant, but new solutions are being found, and valuable experience is being gained.

8.5 ENVIRONMENTAL CONSIDERATIONS

Characterization of plant effluents and discharges has not been possible, because the Synthane pilot plant has encountered numerous equipment and operational problems since it went on stream in early 1976. It is expected, however, that containment and treatment of discharges will neither require special techniques nor create a health hazard. This process differs from the other gasification processes in the gasifier unit only. Downstream processing will be similar. When the pilot plant achieves the ability to operate at steady state for long periods of time, effluent characterization studies can be conducted. This phase will allow determination of problem areas, if any exist, and also create design data to produce a totally environmentally acceptable plant when scaled up to commercial size. The process effluents summary is given in Figure 8-2.

Coal Preparation and Drying

The coal preparation and drying systems used for this process are very similar in design and operation to that of other coal conversion processes. The areas of environmental concern are generally the same; therefore, coal preparation is covered in Appendix B in a generalized fashion.

Gasification

Effluents to the Air - In the coal feed system, coal is charged to the gasifiers in the Synthane design through pressurized lock hoppers. In the design, each gasifier is provided with one lock hopper which discharges alternately into two feed hoppers from which coal is passed to the gasifier using a steam-oxygen mix as the transport medium. The gasifier charging sequence involves filling the vented lock hopper from pulverized coal storage bins, pressurizing the filled lock hopper, and then discharging into the feed hopper. The pressurized lock hopper must be vented to essentially atmospheric pressure when empty of coal in order to be refilled. The main volume of gas from the hopper could be contained in gas holders for recycle. However, various amounts of residual gas will remain and will be displaced to the atmosphere when fresh coal is fed into the hopper. The extent of the pollution problem depends on the pressurizing gas. Where this parameter has been determined in the design, the composition of the gases can be estimated.

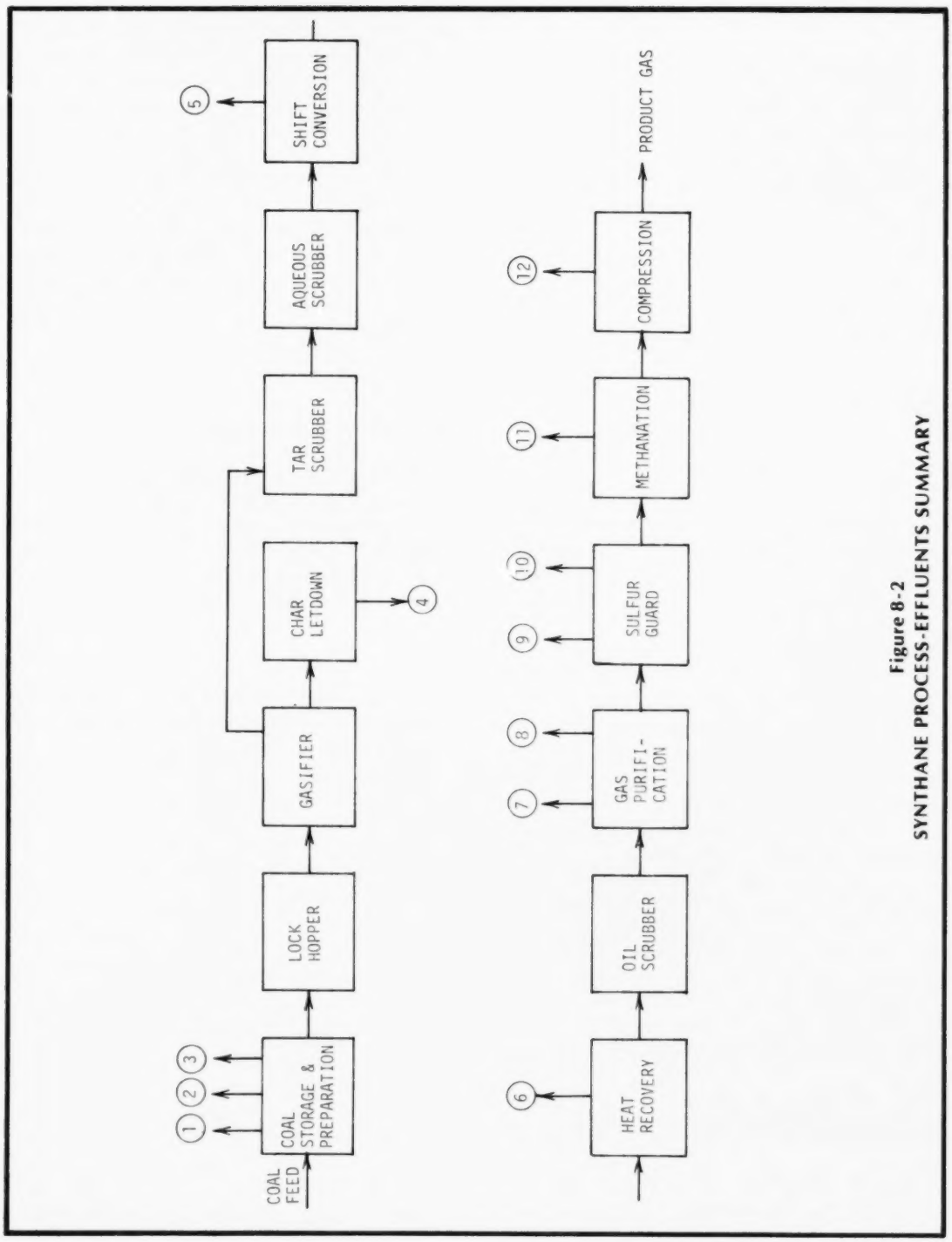

Figure 8-2
SYNTHANE PROCESS-EFFLUENTS SUMMARY

SYNTHANE PROCESS-EFFLUENTS SUMMARY FOR FIGURE 8-2

Stream #	Description
1	Particulates due to wind
2	Precipitation runoff
3	Particulates due to grinding operation
4	Char to utility boiler
5	Spent catalyst
6	Condensate to waste water treatment
7	Condensate to waste water treatment
8	Spent Benfield solution
9	Regeneration gas vent
10	Spent bed media
11	Spent catalyst
12	Condensate to water treatment

The lock hopper system for the new Synthane pilot plant will use carbon dioxide as the pressurizing medium. This will be vented directly to the atmosphere. Some contaminants may enter into the vent stream since the system will be heated and will cause some devolatilization of the coal. This particular problem will need to be evaluated during actual operation of the system.

Liquid and Solid Effluents - The char formed in the char letdown system, in the gasifier, is discharged down through the center of the distributor and into the char cooler attached to the gasifier. Spray water quenches the char, which is at 1,700°F, and high pressure steam is produced. The steam is filtered for fines removal and is used in the shift converter. The char is discharged into lock hoppers and picked up by low pressure steam. In a commercial plant the char would be used to generate steam for the process. In the pilot plant, it will be used as landfill material. This is not expected to pose a problem, but a component analysis should be made and a leachability study conducted.

Quench and Dust Removal

Effluents to the Air - This system is contained, so there will be no emissions to the air.

Liquid and Solid Effluents - The quench and dust removal segment of the process does not itself emit any pollutants directly to the environment.

Shift Conversion

Effluents to the Air - The shift conversion process is a totally contained procedure, so no effluents are emitted to the atmosphere.

Liquid and Solid Effluents - There are no process streams discharged from this unit. However, spent catalyst used in the conversion process will require periodic removal and replacement. The catalyst can be disposed of in a landfill or reprocessed for metals recovery.

Gas Purification

Effluents to the Air - There will be no discharges to the atmosphere for the purification plant.

Liquid and Solid Effluents - The gas purification or acid gas removal process used is the Benfield or hot potassium carbonate system. In the process, carbon dioxide and hydrogen sulfide absorption takes place in a concentrated aqueous solution of potassium carbonate which is maintained above the atmospheric boiling point of the solution. After the hydrogen sulfide and carbon dioxide are removed from the main product gas stream, they are removed from the Benfield solution and further processed to obtain elemental sulfur. The Benfield Process itself does not produce effluents due to solvent degradation. There are no contamination problems and solvent loss is by mechanical losses only.

Methanation

Effluents to the Air - No effluents are discharged.

Liquid and Solid Effluents - No effluents are discharged.

Auxiliary Facilities

A generalized discussion of auxiliary facilities common to most coal conversion plants is given in Appendix A.

Sulfur Balance

A typical sulfur balance breakdown is given in Table 8-1.

Table 8-1
SYNTHANE PROCESS SULFUR BALANCE

	percent
Hydrogen sulfide converted to sulfur product	60.0
Char	28.6
Organic sulfur in raw gas	0.9
Sulfur in aqueous condensate	4.9
Tar	5.6
	100.0

9. WELLMAN-GALUSHA GASIFICATION PROCESS

The Wellman-Galusha Process, developed by McDowell-Wellman Engineering Company of Cleveland, Ohio, has been in commercial use for more than 35 years. The Wellman Engineering Company has been making various types of gasifiers since 1896. Over 150 of the more recent Wellman-Galusha Gasifiers have been installed worldwide for different industrial applications. Feedstocks such as anthracite, coke, and bituminous coals have been used in the gasifiers. Glen-Gery Brick Company, Reading, Pennsylvania, operates six gasifiers with anthracite coal and air. Bituminous coal gasification with oxygen has not been done commercially.

9.1 PROCESS DESCRIPTION

There are two types of Wellman-Galusha Gasifiers, the standard type and the agitated type. The rated capacity of an agitated gasifier is about 25 percent higher than that of the standard gasifier of the same size, and, unlike the standard gasifier, it can handle volatile caking bituminous coals. The agitated gasifier, as shown schematically in Figure 9-1 will be described in the following discussion.

The gasifier itself is water-jacketed. Water in the jacket completely surrounds the gasifier and also covers the top. The inner wall of the gasifier is steel plate and does not require a refractory lining. The agitator has a revolving horizontal arm which also spirals vertically below the surface of the coal bed to retard channeling and to maintain a uniform fuel bed. The agitator arm and its vertical drive shaft are made of water-cooled heavy steel tubing. The arm can be revolved at varying speeds, and its position within the fuel bed may be changed as desired for different feedstocks and operating rates. A revolving step-type grate is mounted eccentrically at the bottom of the gasifier on a center post. It distributes the air-steam blast into the coal bed and forces the ash formed into the ash bin.

Crushed coal is fed into the coal bin and flows into the feeding compartment by gravity. The feeding compartment continuously feeds the coal into the gasifier by gravity through the vertical feed pipes. Four slide valves control the flow of coal in and out of the feeding compartment. The upper valves are always open except when refilling. The continuous flow of coal into the gasifier is highly desirable because it assists in maintaining the coal bed and gas quality in a stabilized condition.

A fan supplies the air required for gasification. The air is passed over the top of the water in the jacket and picks up steam required for the blast. Saturation of the blast is regulated by adjusting the jacket water temperature. Normally, the temperature is between 150°F and 180°F. A thermostat controls the water supply to the jacket. Blast mixtures of air and carbon dioxide, oxygen and carbon dioxide, or oxygen and steam can also be used.

The blast is introduced through the saturation pipe into the ash bin section underneath the grate. It is distributed through the grate into the coal bed, and it passes upward through the ash, combustion, and gasification zones. Combustion and gasification reactions occur, resulting in a gas containing mainly carbon monoxide, carbon dioxide, hydrogen, and nitrogen. The hot gas produced dries and preheats the incoming coal and then leaves the gasifier. Ash is withdrawn continuously through the eccentric grate, collected in the ash bin, and later sent to disposal.

Gas leaving the gasifier is passed through a cyclone, where the heavy dust particles, mainly ash and char, are removed. The cyclone can also be flooded with water during a shutdown to an elevation a few inches above the internal gas-outlet, thus using the water seal to eliminate a mechanical valve.

The gas leaving the cyclone can be used hot if its sulfur content is acceptable. Otherwise, it

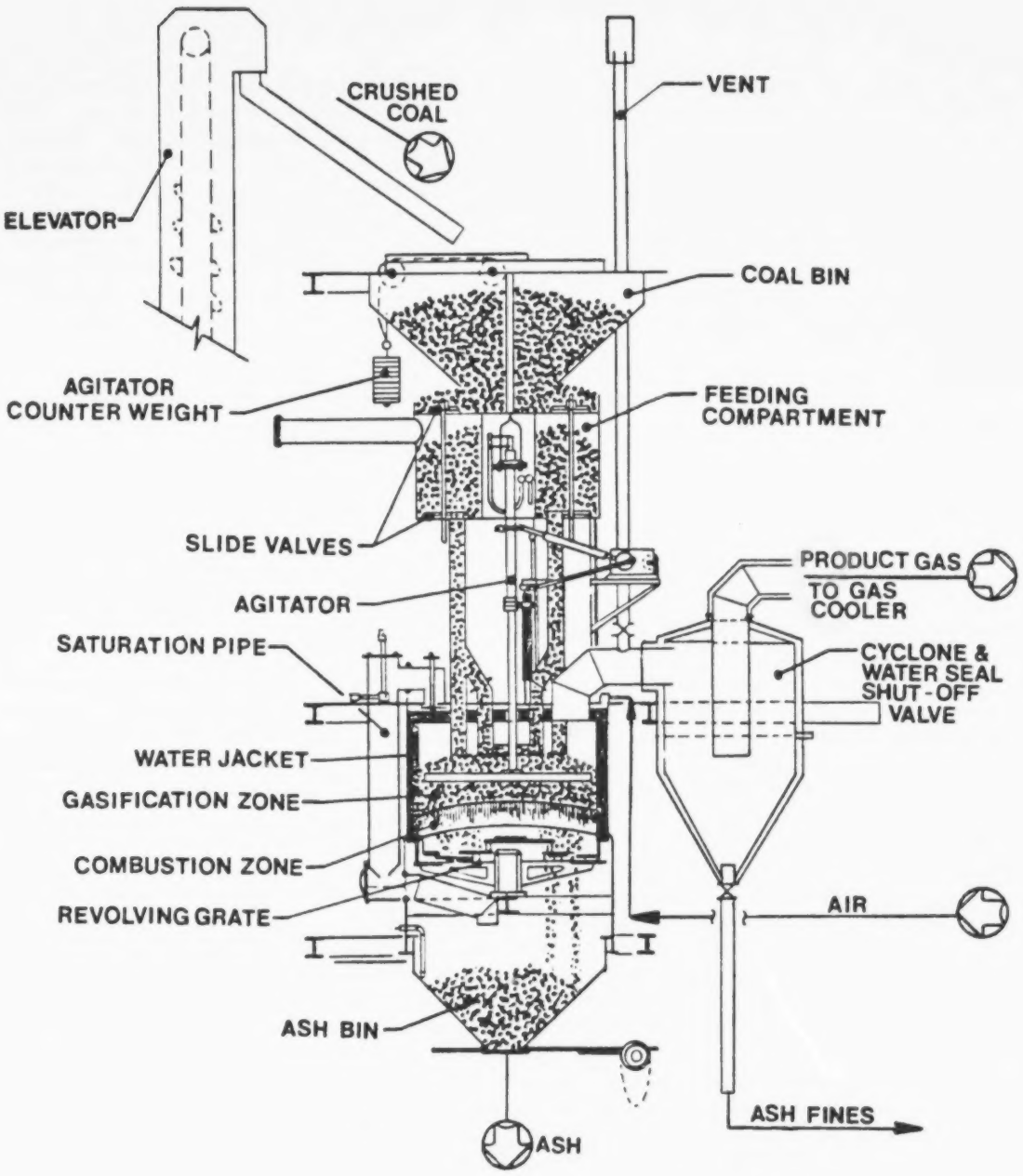

Figure 9-1
WELLMAN-GALUSHA PROCESS SCHEMATIC

can be scrubbed and cooled in a direct contact countercurrent water cooler and then sent for sulfur removal. If the gas contains tar, the tar may be separated from the cooled gas by mechanical or electrical precipitation methods. The resulting gas is a low-Btu product gas. A medium-Btu gas can be produced by using oxygen instead of air.

Cooling-water-overflow from the jacket and the agitator is not contaminated and can be cooled and recirculated. Blowdown from the gas cooler is sent to waste water treatment.

9.2 PROCESS ADVANTAGES

- Gasifier can be operated with anthracite, bituminous, charcoal or coke. The use of an optional coal bed agitator allows gasification of caking coals;
- Gasifier can be operated with air or oxygen;
- Gasifier can be started up in about four hours; gasifier can be maintained in a stand-by condition with a few minutes of air blowing once a day;
- Small reactor size may be advantageous for small scale industrial application;
- Gasifier has been operated commercially and reliably for many years.

9.3 PROCESS LIMITATIONS

- Maintaining the coal bed temperature below the ash fusion temperature limits the maximum process efficiency;
- By-products require additional processing for recovery;
- Process condensate and by-products require additional processing for environmental acceptability;
- Low operating pressure may limit utilization possibilities;
- Limited reactor size may necessitate use of multiple units in parallel for large installations.

9.4 PROJECT HISTORY

The Wellman-Galusha Process has been commercial for over 35 years. Six units are operating in the U.S. at the Glen-Gery Brick Company, in Reading, Pennsylvania. The units can produce low-Btu gas for industrial use, using air instead of oxygen, or synthesis gas, using oxygen. The plants in use are small gasification units serving single large industrial plants. The gasifier could serve a complex of smaller plants requiring a high-Btu gas as a substitute natural gas in special cases.

In 1974, the OCR awarded a $95,000 contract to McDowell-Wellman to determine the feasibility of constructing a fixed-bed gasifier for operation on caking coals. Under the contract, the firm supported its findings with a preliminary engineering design of the gasifier. It would operate at 300 psi on highly-caking coals with air to produce a low-Btu product or oxygen moderated with either carbon dioxide or steam to produce a medium-Btu product suitable for methane synthesis.

In February 1975, Applied Technology Corporation announced it had reached agreement in London with Wellman Incandescent Ltd. for exclusive rights in North and South America to Wellman's coal gasification technology.

More recently, EPA and ERDA began cooperating to evaluate small-sized gasifiers in ERDA's Industrial Program. The gasifiers utilize up to 200 tons of coal per day. They will serve as a practical energy source, as a basis for obtaining data to make improvements in technology, and as a source of environmental information. The ERDA phase of the program began in early 1976. The agency has signed agreements with:

- ACUREX Corporation, Aerotherm Division, Mountain View, California, to produce fuel for use in a brick kiln at the Glen-Gery Co-pany plant in York, Pennsylvania;
- The University of Minnesota, Minneapolis, to produce boiler fuel for space heating of the Duluth campus;

- Pike County, Kentucky, to provide boiler fuel for heating and cooling of housing, a fire station, school, shopping center, and fuel for an industrial park near Pikeville.

9.5 ENVIRONMENTAL CONSIDERATIONS

A small amount of tar is produced with bituminous coal, 0.001 lb/SCF of gas, and carried with the product gas. If it is removed from the gas before use, final disposition of this material would have to be ascertained for each installation.

Exit gasifier jacket water and cooling water for the agitator arm are relatively uncontaminated and can be recirculated after cooling. However, water discharged from the combination cyclone and water seal shutoff valve and the gas scrubber require treatment before disposal.

The ash produced from the Wellman-Galusha Gasifier contains about 0.1 percent carbon and can be disposed of by landfill.

Auxiliary Facilities

A generalized discussion of auxiliary facilities common to most coal conversion plants is given in Appendix A.

Sulfur Balance

Sulfur balance data are not available.

10. WINKLER PROCESS

The Winkler Process developers are Davy Powergas, Inc., Lakeland, Florida, a subsidiary of Davy International Ltd., London, and its affiliate, Bamag Verfahren-Stecknik GmbH, West Germany. This process was developed in Europe over 50 years ago. The process was constructed commercially at 16 plants in a number of countries, using a total of 36 generators. These plants are still operating with the largest having an output of 1.1 MMSCFD. The plants produce low-Btu fuel gas, with air instead of oxygen, and synthesis gas for the production of methanol, ammonia, and oil by Fischer-Tropsch synthesis.

10.1 PROCESS DESCRIPTION

In the Winkler Process coal is gasified at about 1,700°F and 2 atm in a turbulent bed of particles using oxygen and steam, to make medium-Btu gas for fuel or synthesis. Most of the residual char is blown overhead as a result of the high gas velocity of 5 to 10 ft/sec. Most of the gas is then cooled and cleaned to remove dust and sulfur. The process diagram is shown in Figure 10-1. There are four major steps in the process: (1) coal preparation, (2) gasification, (3) cooling and scrubbing, and (4) sulfur removal.

Coal drying is not always needed, because it is only necessary to avoid surface moisture which would cause difficulties in handling and crushing. Rotating tray dryers are used when drying is necessary. Cool stack gas, 350°F to 400°F, is recycled to control gas inlet temperature so as not to drive off volatiles. Coal is crushed to -8-mesh and sent to the gasifier feed hopper.

Coal from the feed hopper is fed to the gasifier by means of screw feeders. Steam and oxygen are added near the bottom of the reactor, maintaining the particulates in the turbulent bed where reaction takes place without reaching temperatures that would fuse the ash. The bed may be about 1,700°F so that tar and heavy hydrocarbons are destroyed by gasification reactions.

Considerable fines are entrained from the bed, and supplemental oxygen and steam are added to help consume them. The heat exchange surface in the dilute phase about the bed removes heat to protect refractories and for temperature control, generating useful steam. The raw gas is cooled to about 1,300°F before the gas leaves the boiler. The gas then passes through an exchanger to superheat steam, followed by a waste heat boiler and a cyclone to remove entrained char. The gas then goes to a scrubbing tower where it is cooled by direct contact with recirculated water.

Most of the particulates are removed by scrubbing and are separated from the water in a settler. They are included with the char for disposal. Clarified water is cooled by indirect exchange with cooling water before it is recirculated to the scrubber. Net production of this water or gas liquor constitutes sour water containing hydrogen sulfide, ammonia, cyanides, etc., present in the raw gas. The sour water is processed in waste water treating so that it can be reused.

The scrubbed gas will still contain a small amount of dust and is passed through an electrostatic precipitator for final cleanup. Traces of contaminants may remain in the gas after scrubbing, such as ammonia, sulfur, oil, etc.

The next processing step on the gas is sulfur removal by scrubbing with a suitable solution such as amine, hot carbonate, or a glycol type solvent. These can be regenerated by stripping to give a concentrated hydrogen sulfide stream that is sent to sulfur recovery.

10.2 PROCESS ADVANTAGES

- Gasifier can be operated with air or oxygen;
- The absence of tars, oils, and naphthas in the raw gas simplifies control technology requirements;
- The gasifier can be shut down in a few minutes; even after several days the gasifier can be re-started instantly;

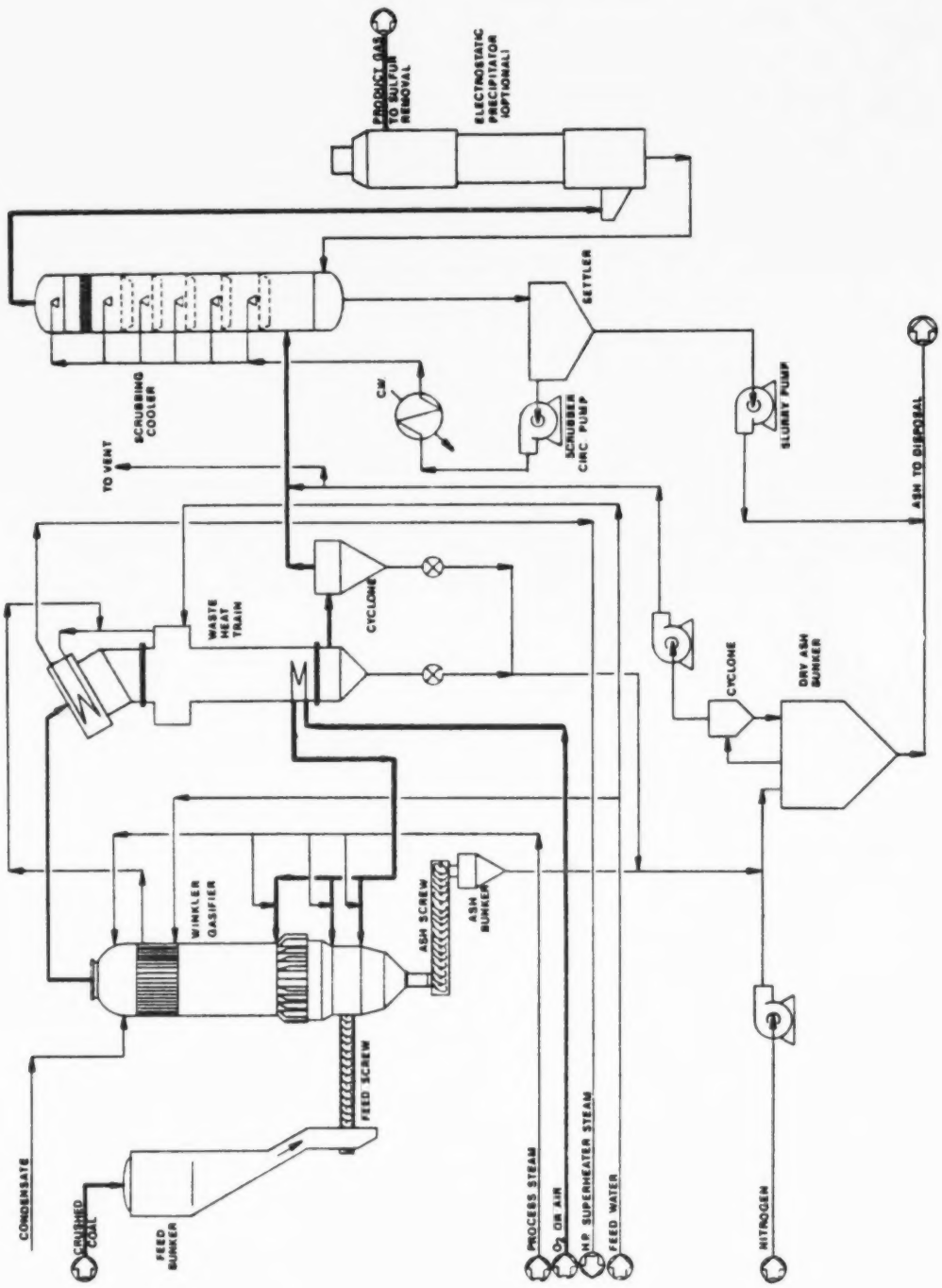

Figure 10-1
WINKLER PROCESS SCHEMATIC

- The uniform temperature and composition of the fluidized-bed provide stable operating conditions;
- Gasifier has been operated commercially and reliably for many years.

10.3 PROCESS LIMITATIONS

- Strongly caking coals may require partial oxidation pretreatment; less reactive coals decrease thermal efficiency and carbon conversion;
- Efficiency is limited due to large amount of unconverted coal which leaves the gasifier; higher temperatures decrease efficiency due to sensible heat losses;
- The large amount of unreacted coal in the char can be burned as a by-product, but if a suitable use is not available, the efficiency of the overall process is greatly reduced;
- Low operating pressure may be a disadvantage for transmission of the product gas or utilization in combined cycle applications;
- Separation of high temperature char particles from the raw gas stream may be an operating problem.

10.4 PROJECT HISTORY

In 1922, Dr. Fritz Winkler conceived the idea of using a fluid-bed for gasifying coal while working on processes for the production of activated carbon in a BASF AG plant. A patent was applied for in September 1922, and development work directed toward making power gas was carried out at Oppau, near Mannheim, in the following years. The first commercial Winkler plant was put into operation at Leuna in 1926. Since then 36 producers in 16 installations have been designed, engineered, and constructed, all by Bamag Verfahren-Stecknik GmbH.

The Winkler Process has provided gas for fuel or power, for synthesis of methanol and ammonia, for Berguis-Hydrogenation, and for the production of hydrogen in Europe and Asia when coal was the only raw material available. All of those commercial plants were designed and operated so that after cooling and particulate removal, the product gas would be delivered at nominally atmospheric pressure.

In mid-1972, Davy Powergas undertook a study to determine if a Winkler Gasifier operating under these proven conditions would be competitive with other available technology. Within the accuracy of the estimates made, none of the commercial processes appeared decisively better than any of the others, and therefore, review was begun of the Winkler Process to determine what its limitations were for current U.S. conditions. It became obvious that the biggest deficit was the low pressure of operations because of (1) large size equipment to handle large volumes of gas, (2) high capital costs because of the product compression station, and (3) high daily operating costs of power for product compression.

Process economic studies were conducted to find the optimum pressure ranges and to assess the magnitude of savings attributable to pressure operations. Conclusions clearly showed that improvements in capital and operating costs would result from pressurization.

10.5 ENVIRONMENTAL CONSIDERATIONS

An advantage of the Winkler Process is that the absence of tars, oils, and naphthas in the raw gas simplifies control technology requirements. The process effluents are summarized in Figure 10-2.

Coal Hopper

Effluents to the Air - The nitrogen vent stream contains the nitrogen which is used to blanket the coal dust feed bins in order to prevent explosions of the fine coal particles. These particles can be removed with filters, cyclones, or scrubbers prior to venting the nitrogen to the atmosphere.

Liquid and Solid Effluents - No effluents are discharged.

Gasifier

Effluents to the Air - No effluents are discharged.

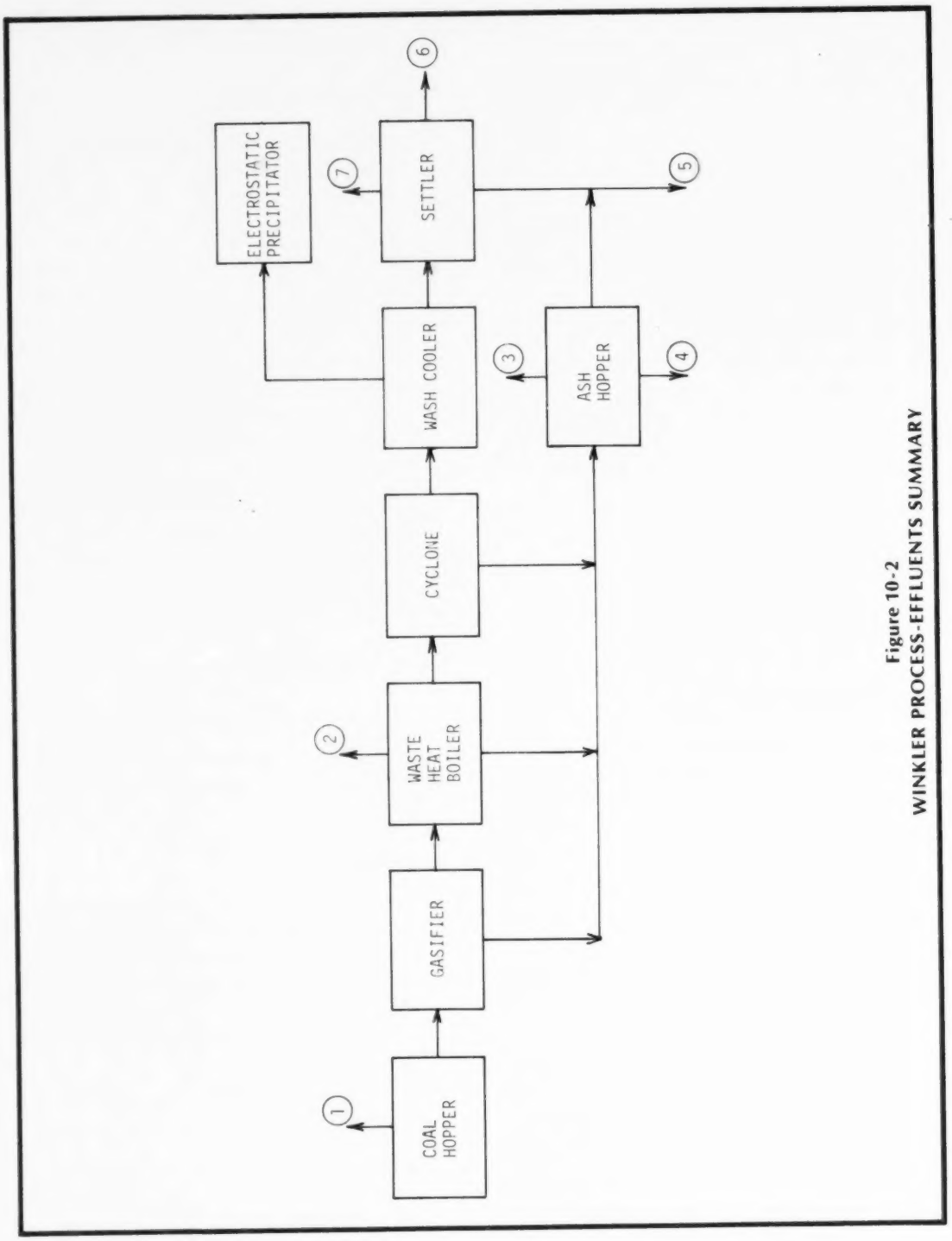

Figure 10-2
WINKLER PROCESS-EFFLUENTS SUMMARY

WINKLER PROCESS-EFFLUENTS SUMMARY FOR FIGURE 10-2

Stream #	Description
1	Nitrogen vent
2	Steam
3	Nitrogen vent
4	Dry ash
5	Ash slurry
6	Condensate
7	Vent

Liquid and Solid Effluents - No effluents are discharged.

Waste Heat Boiler

Effluents to the Air - The only effluent to the air is steam.

Liquid and Solid Effluents - No effluents are discharged.

Ash Hopper

Effluents to the Air - This nitrogen vent stream contains the nitrogen which is used to blanket the dry ash bin in order to prevent further reaction or combustion of the char in the ash. This stream will also contain entrained ash particulates plus some raw product gas or gases evolved from the hot char. The entrained ash particulates in this gas stream can be removed with filters, cyclones, or scrubbers. If there are significant concentrations of raw gas or gas evolved from the hot char in this stream, these contaminants may be controlled by recycling the stream to the raw gas or by incinerating the stream in a flare or boiler, although the nitrogen content of the stream may eliminate this option due to nitrogen oxides formation or non-flammability.

Liquid and Solid Effluents - The dry ash stream is composed of larger ash particles formed in the gasifier which were heavy enough to fall to the bottom of the gasifier and into the screw conveyor plus the ash particles which were removed from the raw gas in the waste heat boiler and in the cyclone. The ash will consist of the mineral matter present in the coal feed with 10 to 30 percent unreacted carbon. The exact composition of the ash is dependent on the composition of the feed coal and the gasifier operating conditions. The dry ash may contain enough unreacted carbon to be utilized as a salable by-product. The char in the ash may be burned as a fuel or may be used as an adsorbent similar to activated charcoal. If the dry ash is a solid waste product, it may be combined with the ash slurry prior to ultimate disposal. Solid treatment processes can be used for ash disposal.

Wash Cooler

Effluents to the Air - No effluents are discharged.

Liquid and Solid Effluents - No effluents are discharged.

Settler

Effluents to the Air - The settler vent stream may contain any of the components in the raw gas which dissolve or condense in the direct contact scrubber/cooler. The ash which is washed out of the raw gas stream is separated from the quench liquor in a settler. The dissolved or condensed components from the raw gas stream that evaporate from the quenching liquor are removed from the settler through the vent. This vent stream may also contain entrained droplets of gas-quenching liquor or ash slurry. The solid and liquid contaminants in this stream can be removed with filters, cyclones, or scrubbers. If there are significant concentrations of contaminants from the raw gas in this stream, they may be controlled by recycling the stream to the raw gas or by incinerating the stream in a flare or boiler.

Liquid and Solid Effluents - The condensate stream is composed of the raw gas-scrubbing liquor plus raw gas condensate from the direct contact scrubber/cooler. The ash which is washed out of the raw gas stream is separated from the quench liquor in a settler, but some

ash particles may be carried along in this blowdown stream. The other components in this stream are the constituents of the raw gas which condense or dissolve in the quench liquor. The components most likely to be present in this stream are water, particulates, ammonia, hydrogen sulfide, and trace elements. Water pollution control processes can be used to remove these contaminants.

The ash slurry stream contains the ash particles which were not removed from the raw gas in the waste heat boiler or in the cyclone. The ash particles are washed out of the raw gas stream in the direct contact scrubber/cooler, and the ash is separated from the quench liquor in a settler. The bottom product removed from the settler is the ash slurry which contains approximately 25 to 35 percent solids. The liquid portion of the slurry is composed of the process condensate and gas-quenching liquor. The ash in the slurry consists of the mineral matter present in the feed coal with 10 to 30 percent unreacted carbon. Suspended solids removal processes can be used to dewater the ash slurry. The recovered water could be recycled to the process condensate and gas-quenching liquor. The dewatered ash or ash slurry is a waste product which requires ultimate disposal. The ash slurry may be combined with the dry ash prior to disposal. Solid waste treatment processes can be used for ash slurry disposal.

Electrostatic Precipitator

Effluents to the Air - None.

Liquid and Solid Effluents - No effluents are discharged.

Auxiliary Facilities

A generalized discussion of auxiliary facilities common to most coal conversion plants is given in Appendix A.

Sulfur Balance

A typical sulfur balance breakdown is given in Table 10-1.

Table 10-1
WINKLER PROCESS SULFUR BALANCE

	percent
Product gas	4.7
Fuel gas	0.2
Claus plant	91.2
Tail gas	0.9
Char and ash	3.0
	100.0

11. CHAR-OIL ENERGY DEVELOPMENT (COED) PROCESS

The COED project was conducted by the FMC Corporation under government sponsorship from September 1966 through December 1975. At that time, the process had been successfully demonstrated, and ERDA funding was discontinued. No further experimental work has been done since that date.

The COED Process produces huge quantities of un-wanted char. At one time, the sponsors thought electric utility companies would buy the char to burn in boilers. No market at all was found for char.

11.1 PROCESS DESCRIPTION

The COED Process converts coal to gas, oil, and char through heating in multistage fluidized-beds, as shown in Figure 11-1. In this process, the coal is first crushed and dried, then is pyrolyzed in a series of four fluidized-bed reactors with successively higher temperatures. The temperature of each fluidized-bed reactor is just below the maximum temperature to which the coal can be heated without agglomerating. The number of stages and the operating temperature vary with the agglomerating properties of the coal. Heat for pyrolysis is provided primarily by burning a portion of the char with oxygen in the presence of steam in the fourth stage of pyrolysis. Nitrogen is used for start-up to fluidize the first stage until enough flue gas is available. Hot gases from the fourth stage flow countercurrent to the char. These gases, which provide the fluidizing medium for the second and third stages of pyrolysis, are then passed to a product recovery system where the gas and oil are produced.

Gas and oil are recovered from vapors coming off from the second pyrolysis stage. These vapors pass into a cyclone which removes the fines. The vapors leaving the cyclone are then quenched directly with water in a venturi scrubber to condense the oil. The gases and oils are separated in a decanter.

The gas is desulfurized in the gas-cleaning plant, then it is enriched with steam by a steam reformer. Part of the product gas is converted to hydrogen and used in the process; the balance of the product gas can either be scrubbed and sold as fuel gas or be converted to pipeline gas or hydrogen.

The oil from the decanter is dehydrated and filtered in a rotary pressure precoat filter. The solids-free oil is then pressurized and mixed with hydrogen in a fixed-bed catalytic reactor (hydrotreater). The hydrotreater removes nitrogen, sulfur, and oxygen, which are reacted with hydrogen to form ammonia, hydrogen sulfide, and water, and produces a heavy synthetic crude oil with a specific gravity of 0.9.

The char produced by the process is desulfurized in a shaft kiln. In the kiln, hydrogen is added to the char, which produces hydrogen sulfide; the hydrogen sulfide is then absorbed by an acceptor, such as calcined limestone or dolomite. After desulfurization, the char and spent acceptor, which can be regenerated, are separated in the continuous fluidized-bed separator. Product char can be reacted with steam and oxygen in a gasifier to generate low-Btu gas. The rank of coal processed and the marketability of the end product determine the final use of the char and gas.

11.2 PROCESS ADVANTAGES

- The process can handle caking coals without the preoxidation or recirculation of char usually necessary to prevent agglomeration in the system;
- The process achieves high yields of oil with minimum-sized equipment;
- The process operates at low pressure (less than 10 psia) which permits the use of conventional oil processing equipment.

11.3 PROCESS LIMITATIONS

- The process has comparatively low thermal efficiency, a limitation common to all pyro-

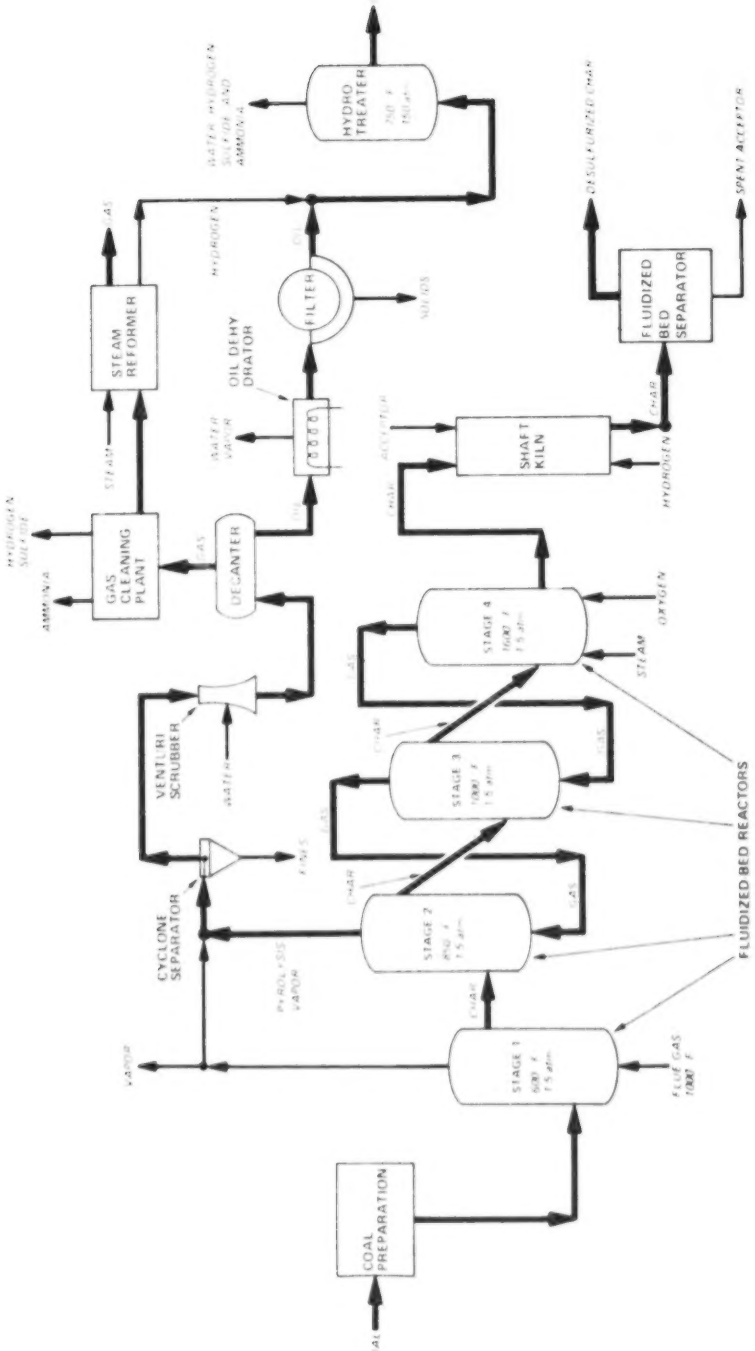

Figure 11-1
COED PROCESS SCHEMATIC

lysis and hydrocarbonization processes;
- Carbon conversion is low; research is being done to investigate gasification of the large amount of char produced.

11.4 PROJECT HISTORY

The COED project, initiated in 1962 under the auspices of the OCR, was tested for several years in bench-scale research studies. In 1965, FMC installed a process development unit at its Chemical Research and Development Center in Princeton, New Jersey, capable of processing 100 pounds of coal per day. Twelve different kinds of coal were evaluated.

FMC Corporation entered into a second contract with OCR in September 1966. This contract was to (1) continue the investigation of the pyrolysis of coal using the existing process development unit and (2) design, construct, and operate a pilot plant capable of converting 36 TPD of coal to a low-sulfur synthetic crude oil. The plant, located in Princeton, New Jersey, was completed in July 1970. The pyrolysis section of the pilot plant has been in operation since then and the hydrotreating section since June 1971.

FMC entered into its last contract with OCR in 1971. Through 1974, the COED pilot plant processed about 21,000 tons of coal from seven different geographic sources, ranging in rank from lignite to high volatile A bituminous coal. In 1974, high volatile B bituminous coal from western Kentucky and high volatile A bituminous coal from West Virginia were processed. These are the most highly agglomerating coals to be processed in the pilot plant. The circulation of solids between multiple fluidized-bed reactors, the filtration of coal oil, and the upgrading of the coal oil to synthetic crude oil through fixed-bed hydrotreating have been demonstrated successfully. The plant was also operated to test new equipment and provide char and oil for further evaluations. The pilot plant operated successfully at design capacity and several 30-day runs were made.

Current plans are to incorporate the COED Process into the Illinois Coal Gasification Group (ICGG) in Perry County, Illinois. ICGG's COGAS Process will gasify the char that is produced from the COED Process. To that end, ERDA has awarded ICGG a $24 million contract.

11.5 ENVIRONMENTAL CONSIDERATIONS

The COED Process has demonstrated its ability to convert practically any type of coal into very low-sulfur synthetic crude oil, clean fuel gas, and char in an environmentally acceptable manner. Essentially all of the sulfur in the coal is converted into hydrogen sulfide which is subsequently converted into elemental sulfur. Since the initial operation of the plant in July of 1970, over 18,000 tons of various agglomerating and nonagglomerating coals were processed. During this time a large amount of experience has been gained with respect to characterization and handling of waste streams. A process effluents summary is given in Figure 11-2. As can be seen, these methods are the same as those used in other processes. None of the streams that are finally vented to the atmosphere exceeds current allowable emission standards.

Because of the long-term pilot operation, various tests have been made to determine the compatibility of COED syncrude with existing combustion equipment and the environmental effects of the product usage.

Studies have been conducted on syncrude by the Atlantic Richfield Company to define those refinery processes where the syncrude could best be used. A subsequent study has been carried out by Chem Systems in which their refinery model showed syncrude to have the same value, to a refinery, as sweet crude. A promising use of the product is to distill it into naphtha and No. 4 fuel oil. The sulfur content of the syncrude is generally about 0.1 percent. In addition to the refinery test, about 17,000 gallons of COED syncrude were used to power the Navy destroyer USS Johnston. The successful test was made during a 30-hour period in November of 1973. The syncrude was also tested as a fuel for a small industrial boiler firing 1.5 million Btu/hr. All emissions from syncrude combustion were significantly lower than those from a typical No. 4 residual fuel.

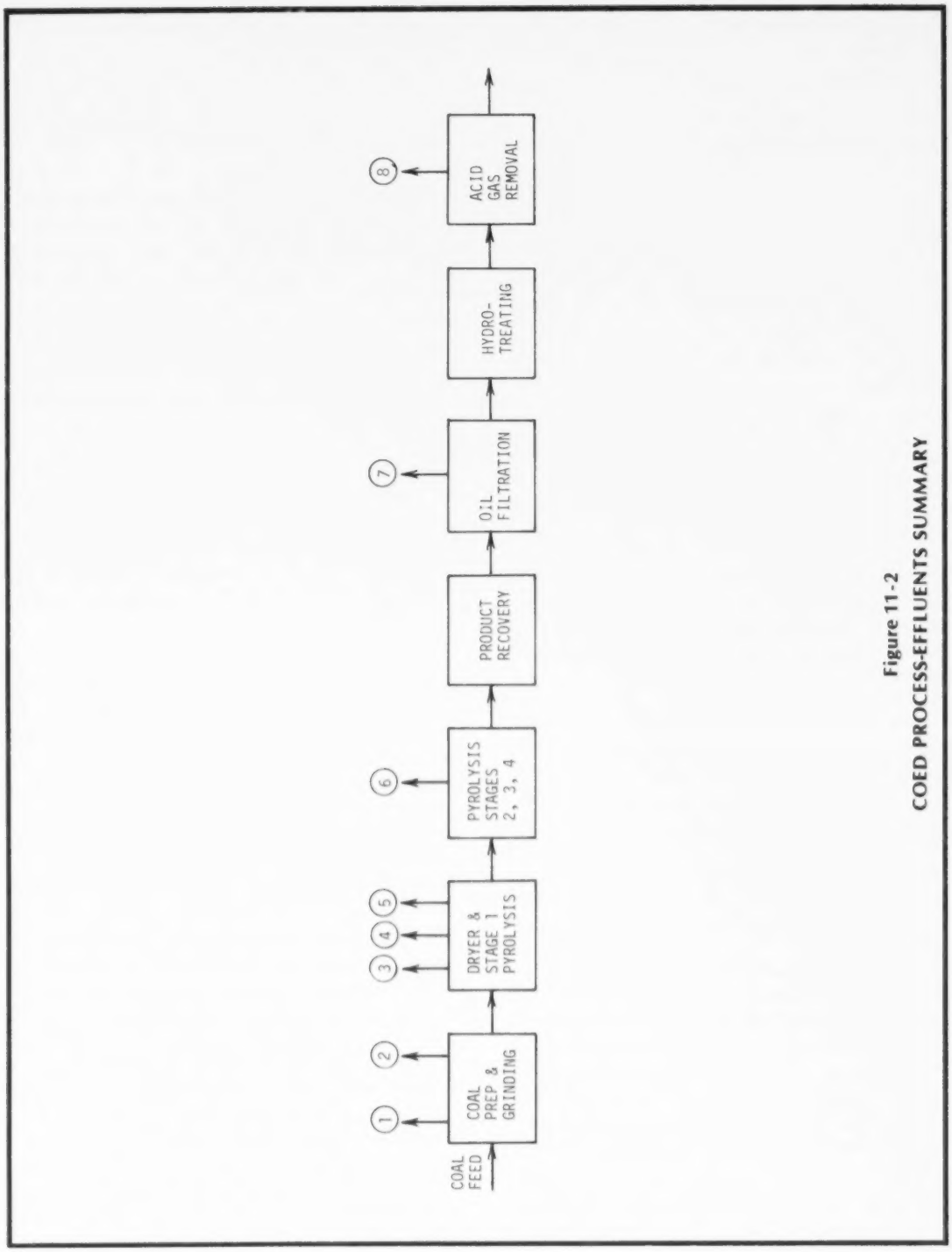

Figure 11-2
COED PROCESS-EFFLUENTS SUMMARY

COED PROCESS-EFFLUENTS SUMMARY FOR FIGURE 11-2

Stream #	Description
1	Dust due to wind
2	Runoff due to precipitation
3	Purge gas to boiler stack
4	Oily wet char fines to coal feed
5	Aqueous condensate to stage four pyrolyze
6	Product char stream
7	Char fines and filter aids to coal feed
8	Spent Benfield solution

Coal Drying and First Stage Pyrolysis

Effluents to the Air - In the FMC design, clean natural gas is burned sub-stoichiometrically both to dry the feed coal and to heat the fluidizing gas for the first stage of pyrolysis. A cascade of two internal gas cyclones is provided for both the coal dryer and first pyrolysis reactor. Gas from the pyrolyzer is circulated through fluidized-bed heater for use in the coal dryer. The gas from the coal dryer passes through an external cyclone and is then scrubbed in a venturi scrubber-cooler which removes coal and char fines and traces of coal liquids. The fines are recycled back to the first stage pyrolyzer.

The scrubber effluent passes into a gas-liquid separator, where the liquor stream is decanted to remove solids. The solids are recycled back to the coal feed and the water is recycled back to the venturi scrubber. The gas is compressed and recirculated back to the gas heaters except for a purge stream which is vented to the atmosphere. The stream will contain about 3.7 percent carbon monoxide. The stream will need to be treated by injection into boiler stacks. The purge vent is expected to be sulfur free.

Liquid and Solid Effluents - All the liquid and solid streams are recycled back into the process.

Pyrolysis Stages Two, Three, and Four

The next three pyrolysis stages are closed systems, and as with the first stage, gaseous liquid effluent will be recycled to other stages of the process.

The char produced in this section will be sent to a gasifier for hydrogen production in a commercial plant.

Product Recovery

There are no effluents generated in this section that are discharged to the environment. The waste liquor purge from the scrubbing circuit is returned to the last pyrolysis stage.

COED Oil Filtration

There will be no gaseous or liquid effluents generated in this process. The filter cake which, from pilot plant data, contains about 38 percent oil, 52 percent char, and 10 percent filter aid is recycled to the coal feed stream.

Hydrotreating

The spent catalyst from the hydrotreating reactors will be the only discharge from this section.

Auxiliary Facilities

A generalized discussion of auxiliary facilities common to most coal conversion plants is given in Appendix A.

Sulfur Balance

A typical sulfur balance breakdown is given in Table 11-1.

Table 11-1
COED PROCESS SULFUR BALANCE

	percent
Syncrude	0.5
Elemental sulfur	54.6
Sulfur emissions	0.2
Char	44.6
Other	0.1
	100.0

12. DONOR SOLVENT LIQUEFACTION PROCESS

The Donor Solvent Process for coal liquefaction is being developed by the Exxon Research and Engineering Company, Baytown, Texas. A $12 million contract between ERDA and Exxon was initiated in January 1976. However, under the terms of the contract, details of prior development work on the process conducted between 1966 and January 1976 are confidential.

12.1 PROCESS DESCRIPTION

Steps in the Donor Solvent Process involve engineering and design technology similar to that practiced in the petroleum industry. The process was designed to permit process control, allow for feeding different coals, and allow product distribution to vary based on market demand. In this process, the donor solvent provides a mechanism to allow intimate contact between hydrogen and dispersed coal fragments. The donor hydrogen content of the spent solvent is restored after liquefaction in the solvent hydrogenation reactor. This step also reduces the sulfur, nitrogen, and oxygen contents of the recycle solvent. The donor hydrogen content is the major parameter used to evaluate the effectiveness of various catalysts and processing conditions to produce good quality donor solvent. A schematic of the process is provided in Figure 12-1.

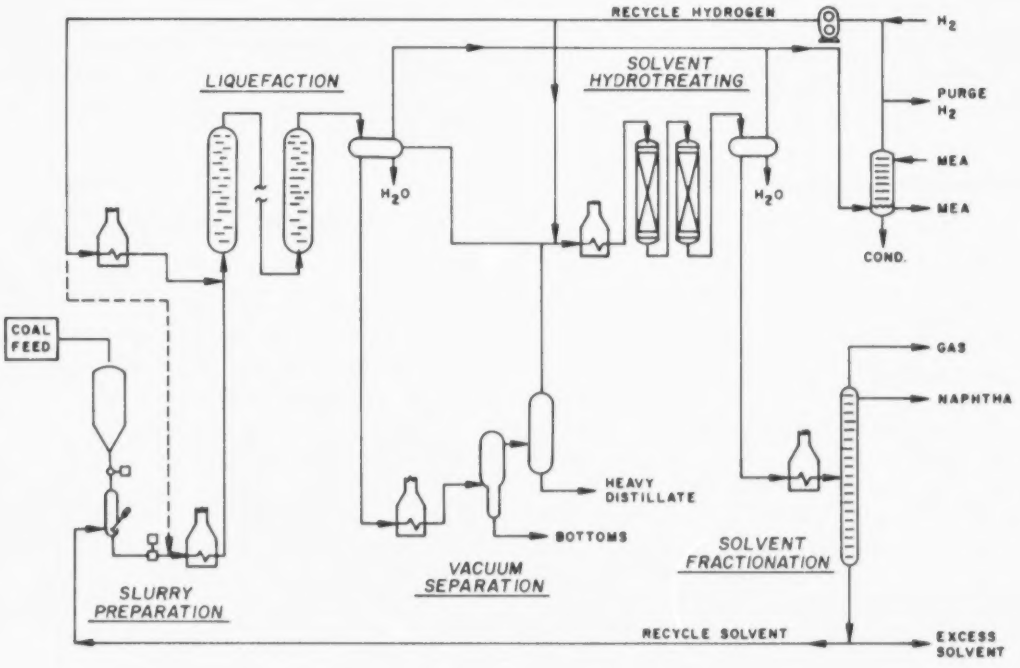

Figure 12-1
DONOR SOLVENT PROCESS SCHEMATIC

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The coal is dried and ground to -30-mesh and mixed with recycle solvent to form a slurry. Hydrogen is normally preheated separately and combined with preheated slurry at the reactor inlet. An alternate mode of operation is to combine the hydrogen with the slurry before preheating.

After liquefaction, the product goes to the first stage of separation. Water is removed, hydrogen is recycled, and heavy liquid products are sent to the vacuum separation section.

The primary vacuum flash tower removes the mineral matter and unreacted coal. The secondary vacuum tower is used to remove a heavy distillate which becomes the endpoint of the recycle solvent. This overhead from the secondary vacuum flash tower is then combined with the lighter liquid stream recovered from the liquefaction reactor separator system and fed to the solvent hydrotreating section, consisting of fixed-bed catalytic reactors. The solvent and naphtha from the solvent hydrotreating section are then separated by fractionation. Most of the solvent is recycled, as is the hydrogen, after undergoing cleanup in a monoethanolamine scrubbing system.

12.2 PROCESS ADVANTAGES

- The process is designed to permit use of different coal feeds and to produce a variety of products;
- Gas generated in the liquefaction area is used as fuel or for high purity hydrogen manufacture;
- The solvent carries the coal into the reactor, helps to dissolve the coal particles, and improves operability as compared to unhydrogenated solvent.

12.3 PROCESS LIMITATIONS

- Information is not available.

12.4 PROJECT HISTORY

Exxon's research on the Donor Solvent Process began in 1966 and has resulted in a commercial study design. A semi-empirical kinetic model of liquefaction yields from Illinois coal has been expanded to include recent results from high-severity liquefaction experiments. Progress has been made in the development of a computer model of the entire integrated Donor Solvent Process. The model will simulate, and link together in a single interfacing package, the six major processing sections: (1) liquefaction, (2) solvent hydrotreating, (3) coking, (4) cryogenic hydrogen recovery, (5) steam/methane reforming, and (6) final product separation.

Evaluations of several process alternatives have begun, including development of a computerized process alternative model to be used as a basic tool for the process engineering and economic studies which are planned. Engineering studies have been initiated to identify and develop equipment and engineering data needed for a safe, operable, and reliable Donor Solvent commercial plant.

12.5 ENVIRONMENTAL CONSIDERATIONS

Environmental quality data for the Donor Solvent Process are not available because a plant has not yet been constructed, and because of the proprietary nature of the contract.

Auxiliary Facilities

A generalized discussion of auxiliary facilities common to most coal conversion plants is given in Appendix A.

Sulfur Balance

Sulfur balance data are not available.

13. FISCHER-TROPSCH SYNTHESIS PROCESS

In 1974, the OCR (now a part of ERDA), awarded the Ralph M. Parson's Company of Pasadena, California a $2.99 million contract to evaluate the coal-oil-gas refinery concept. The contract entails preliminary design work on a Fischer-Tropsch synthesis plant to produce substitute natural gas and motor fuels as the main products.

13.1 PROCESS DESCRIPTION

The only commercial Fischer-Tropsch plant currently in operation is The South African Coal, Oil and Gas Corporation Ltd. (SASOL) plant in South Africa. The process schematic is shown in Figure 13-1. In the SASOL plant design, coal is gasified in a battery of 13 Lurgi high pressure, steam-oxygen gasifiers to produce a gas consisting essentially of carbon monoxide and hydrogen, tars and oil. The gas stream from the gasifier is quenched to remove tars and oil. The scrubbed gas is then sent to a Rectisol^{R} (Lurgi) Process which uses a methanol solvent to remove the remaining tar and oil, carbon dioxide, hydrogen sulfide, ammonia, and phenols. The purified gas stream is then sent to the Fischer-Tropsch synthesis reactor for polymerization. Initially, the gas is split, and part of it is sent through a fixed-bed, catalytic reactor, using an iron/colbalt cata-

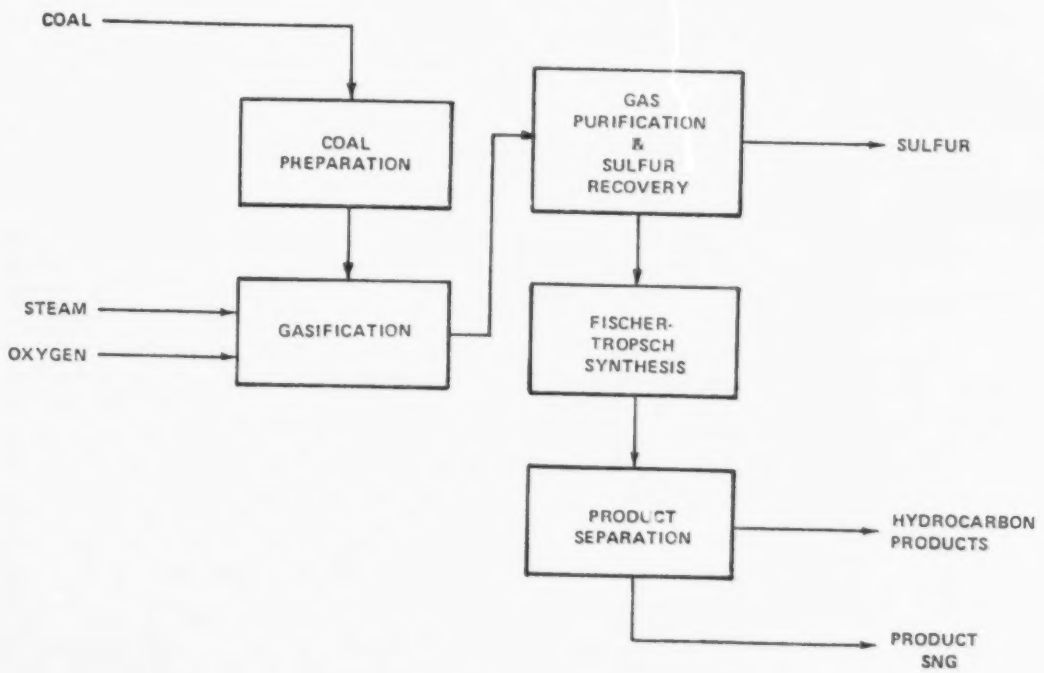

Figure 13-1
FISCHER-TROPSCH PROCESS SCHEMATIC

lyst. The feed gas has a hydrogen/carbon monoxide mole ratio of about 2:1, and synthesis occurs under conditions of 430°F and 360 psi. The products of this synthesis are straight chain, high-boiling hydrocarbons, with some medium boiling oils, diesel oil, LPG, and oxygenated compounds such as alcohols.

The other part of the gas stream is sent to a fluidized-bed catalytic reactor which uses powdered iron as the catalyst. In this reactor, gas and catalyst are circulated along with the synthesis gas. The catalyst is removed by cyclones. Operating conditions are 600°F to 625°F and 330 psi. This process yields petroleum products, alcohol, oil, and gas. A list of typical products obtained from the process includes:

- Fuel gas
- Propane/propylene
- Butane/butylene
- Methylethyl ketone
- Light furnace oil
- Waxy oil
- Methanol
- Ethanol
- Propanol
- Butanol
- Gasoline
- Pentanol
- Acetone
- Naphtha
- Waste acids
- Benzol
- Toluol
- Diesel oil
- Tar
- Creosote
- Ammonium sulfate
- Sulfur

13.2 PROCESS ADVANTAGES

- The product is a mixture of relatively simple hydrocarbons in a semi-refined state and is completely free of sulfur and nitrogen compounds;
- Commercial plants have been developed in Germany, other parts of Europe, and the Union of South Africa.

13.3 PROCESS LIMITATIONS

- Plants are difficult to operate because they typically require much maintenance.

13.4 PROCESS HISTORY

Development of the Fischer-Tropsch Process dates back to the period of 1923 to 1933 when Fischer and Tropsch made extensive studies of the catalytic reduction of carbon monoxide to various hydrocarbon liquids. Following pilot plant operations in 1932, a 1,000 TPY plant was constructed by Ruhrchemie in 1933 and a 30,000 TPY plant in 1936. By 1939, nine plants had been erected in Germany and one in France. In 1950, SASOL was formed and the decision was made to construct a coal conversion plant using the Fischer-Tropsch Synthesis Process. The first barrel of oil was produced in 1954.

Activities related to Fischer-Tropsch synthesis in the U.S. date from the time when the Office of Synthetic Liquid Fuels was set up in 1944. Fischer-Tropsch synthesis has been evaluated from a technical standpoint by the Pittsburgh Energy Research Center. At Louisiana, Missouri, a goverment ammonia plant was converted into a coal liquefaction plant. It used the Fischer-Tropsch synthesis to produce about 100 barrels per day of gasoline and chemicals.

13.5 ENVIRONMENTAL CONSIDERATIONS

Environmental quality data for a Fischer-Tropsch synthesis operation is very sketchy. SASOL has not released information in this area and has been reluctant to provide requested data. Since the front end of the process is basically a Lurgi gasification plant, the effluents for that section are fully defined. Effluents from the Fischer-Tropsch reactors should be limited to spent catalyst and process condensate, both of which can be easily handled. It is possible that future test agreements with SASOL and the U.S. EPA will allow for characterization of effluent streams from the Fischer-Tropsch plant. In addition, The Ralph M. Parsons Company work will include environmental aspects of its conceptual plant and should serve as a good source of information on this matter when the report is finished and released.

Auxiliary Facilities

A generalized discussion of auxiliary facilities common to most coal conversion plants is given in Appendix A.

Sulfur Balance

Sulfur balance data are not available.

14. H-COAL PROCESS

The H-Coal Process is being developed by Hydrocarbon Research, Inc. (HRI) under the joint sponsorship of (1) ERDA; (2) a private industry consortium composed of EPRI, Ashland Oil, Inc., Atlantic Richfield Company, Shell Oil Company, Standard Oil Company (Indiana), Sun Oil Company; and (3) the Commonwealth of Kentucky. The plant site is located at Catlettsburg, Kentucky. The total project funding is $44.4 million with ERDA supplying $32.7 million and industry $11.7 million.

14.1 PROCESS DESCRIPTION

The H-Coal Process is a catalytic hydroliquefaction process that converts high-sulfur coal to boiler fuels and synthetic crude. A schematic of the process is provided in Figure 14-1. Coal is crushed to -60-mesh, dried, slurried with recycled oil, and is then pressurized to about 200 atm. Compressed hydrogen is added to the slurry, and the mixture is preheated and charged continuously to the bottom of the ebullated-bed

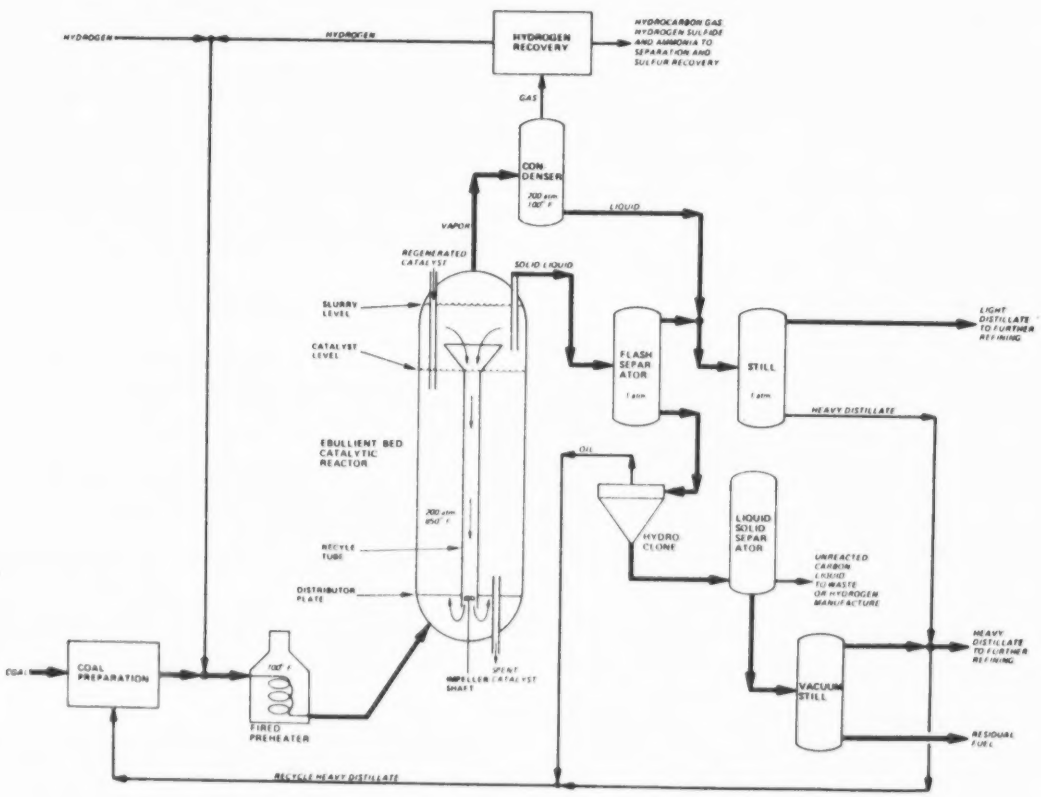

Figure 14-1
H-COAL PROCESS SCHEMATIC

catalytic reactor. The upward passage of internally recycled reaction mixture maintains the catalyst in a fluidized state. Catalyst activity is maintained by the periodic addition of fresh catalyst and the withdrawal of spent catalyst. The temperature of the ebullated-bed catalytic reactor is controlled by adjusting the preheater outlet temperature. Typically, the temperature of the mixture entering the reactor is 650°F to 700°F.

Vapor product leaving the top of the reactor is cooled to separate the heavier components as a liquid. Light hydrocarbons, ammonia, and hydrogen sulfide are absorbed from the gas stream and sent to a separator and a sulfur recovery unit. The remaining hydrogen-rich gas is recompressed and combined with the input slurry. The liquid from the condenser is fed to an atmospheric distillation unit. The liquid-solid product from the reactor, containing unconverted coal, gas, and oil, is fed into a flash separator. The material that is flashed off is passed to the atmospheric distillation unit which yields light and heavy distillate products. The bottoms product from the flash separator, solids and heavy oil, is further separated with a hydroclone, a liquid-solid separator, and by vacuum distillation.

The gas and liquid products, composed of hydrocarbon gases, hydrogen sulfide, ammonia, light distillate, heavy distillate, and residual fuel, may be further refined as necessary. A portion of the heavy distillate is recycled as the slurry medium. The stream containing the unreacted carbon and some liquid will eventually be processed in a commercial installation to produce additional hydrogen needed for the process.

Before the H-Coal Process can become commercially and economically competitive, a method for generating an adequate supply of hydrogen from the process itself must be developed. This is an unsolved problem. The H-Coal Process requires between 14,000 and 20,000 standard cubic feet of hydrogen for each ton of coal processed, depending on the type of oil produced. In the pilot plant some of the hydrogen required has been obtained from the gas produced by the ebullated-bed reactor. Additional hydrogen has been purchased to meet processing demands. In a commercial operation, hydrogen demand will be met by manufacture on-site. Because the H-Coal Process converts about 90 percent of the carbon contained in the coal to a liquid, the feed to the hydrogen plant could be liquid rather than solid. This suggests that commercial hydrogen manufacturing processes could be adapted. The solid cake char could also be used to produce hydrogen.

Another of the principal unsolved problems in the H-Coal Process (and in other liquefaction processes) is the effective separation of the solids from the fuel products. In the H-Coal Process, hydroclones are capable of removing about two-thirds of the solids so that the liquids can be recycled for slurrying the coal. HRI has also been investigating other methods of separating solids from liquids, such as magnetic separation, filtration, centrifugation, and solvent precipitation. Magnetic separation has shown only limited effectiveness. Separation of the solids by filtration has not been conclusive, although filtration rates of 150 lb/hr/sq ft and relatively dry filter cakes have been achieved by using continuous drum pressure filters.

14.2 PROCESS ADVANTAGES

- Direct catalytic processes use less hydrogen in converting coal to liquids than do non-catalytic or indirect catalytic hydrogenation processes;
- The ebullating bed catalytic reactor converts about 90 percent of carbon contained in coal to a liquid;
- The solids residue can be used for hydrogen manufacture;
- The reactor configuration offers good temperature control, constant catalyst activity, and a consistent quality of liquid product.

14.3 PROCESS LIMITATIONS

- An external hydrogen source is required;
- Before the H-Coal Process can become commercially and economically competitive, an adequate supply of hydrogen must be generated from the process itself;

- As in other liquefaction processes, effective separation of solids from the fuel products must be developed.

14.4 PROCESS HISTORY

The H-Coal Process was developed by HRI as a further application of the ebullated-bed processing technology originally used to convert heavy oil residues from petroleum into lighter fractions (H-Oil Process). Early development of the H-Coal Process, beginning in 1964, involved research with a bench-scale unit and a process development unit and preparation of a conceptual process design. An independent evaluation in 1968 confirmed the technical and economic feasibility of the H-Coal Process.

Based on the data obtained from the bench-scale and process development units, design and engineering of the pilot plant began under the current contract in December 1973. During 1974, design of the coal preparation section of the pilot plant was completed to the extent that engineering and plant layout could begin. HRI concentrated, however, on the design and engineering for the ebullated-bed reactor, since the equipment needed for this section requires long lead times. Engineering for other sections of the pilot plant was started in late 1974. Also during 1974, three possible sites for construction of a pilot plant were evaluated. Based on detailed environmental assessments, it was decided during the second quarter of 1975 to locate the plant adjacent to the Ashland Oil, Inc. refinery in Catlettsburg, Kentucky. Except for the steam supply, this arrangement would allow the utility system of the pilot plant to be shared with that of the refinery. All process descriptions, equipment specifications, and planning drawings were completed for the coal preparation section. Work in the hydrogenation area involved the modification and rearrangement of major equipment to conform to the physical characteristics of the new plant site. Preliminary process designs were also completed for the solid-liquid separation techniques of filtration, centrifugation, and solvent precipitation.

14.5 ENVIRONMENTAL CONSIDERATIONS

Studies are being conducted to identify all product and waste streams to be produced by the pilot plant. The probable quantity and composition of each of these streams will also be estimated. A final report is expected to be issued in the near future.

Auxiliary Facilities

A generalized discussion of auxiliary facilities common to most coal conversion plants is given in Appendix A.

Sulfur Balance

A typical sulfur balance breakdown is given in Table 14-1.

Table 14-1
H-COAL PROCESS SULFUR BALANCE

	percent
Synthetic crude	1.8
By-product sulfur from Claus plant	87.2
Tail gas	0.9
Flue gas	10.1
	100.0

15. SOLVENT REFINED COAL (SRC) PROCESS

The SRC Process is being developed by Pittsburgh & Midway Coal Mining Company (PAMCO), a subsidiary of Gulf Oil Corporation, under the sponsorship of ERDA. A 50 TPD pilot plant is located in Ft. Lewis, Washington, and current funding, 100 percent supplied by ERDA, is set at $82 million. The operation and evaluation of the modified pilot plant is scheduled to run through 1980. A 6 TPD pilot plant, sponsored by ERDA, EPRI, and Southern Company Services is operating at the Gaston steam power plant located near Wilsonville, Alabama.

15.1 PROCESS DESCRIPTION

There are really two SRC processes - SRC I and SRC II. SRC I creates a solid fuel as its final product, while SRC II produces a liquid.

The SRC I Process converts high-sulfur, high-ash coals to low-sulfur, low-ash solid fuel. Figure 15-1 shows a schematic of the process. The coal is first pulverized and mixed with a coal-derived solvent in a slurry mix tank. The slurry is combined with hydrogen and is then pumped through a fired

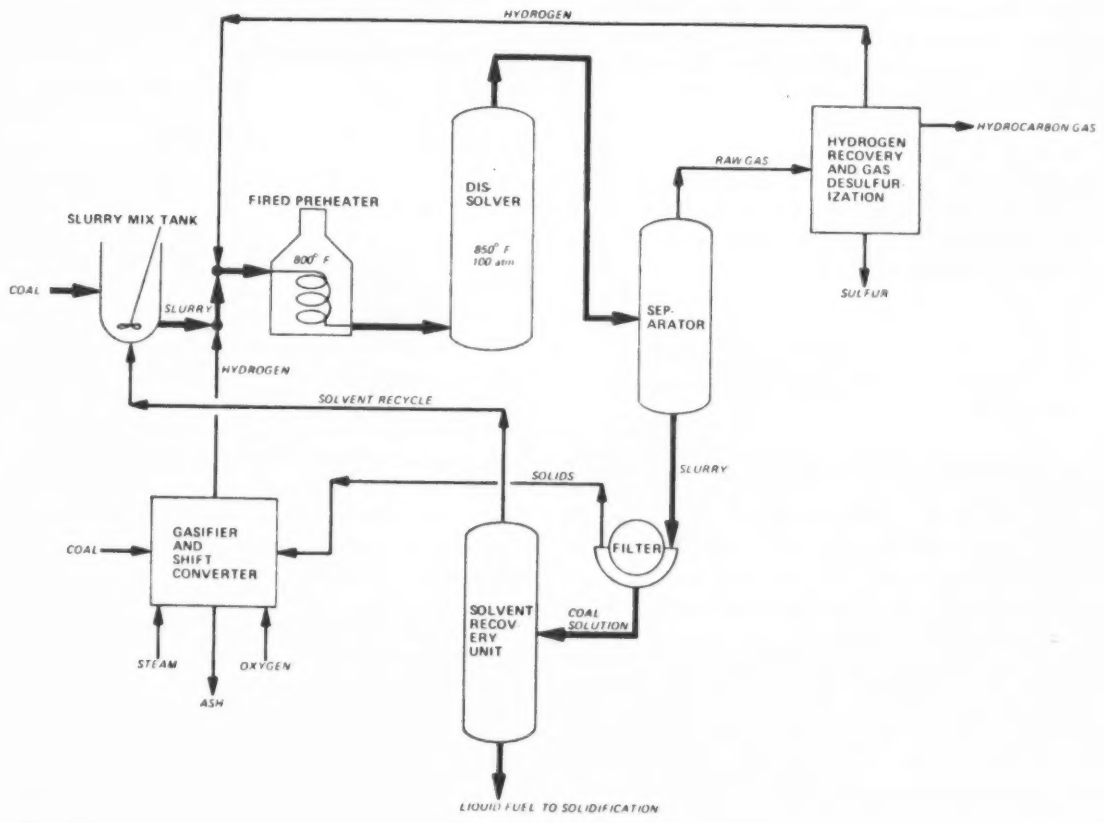

Figure 15-1
SRC PROCESS SCHEMATIC

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preheater and passed into a dissolver. In this unit, the coal is hydrogenated and thereby depolymerized, leading to an overall decrease in product molecular weight and dissolution of the coal. The solvent is also hydrocracked in the dissolver unit, yielding lower molecular weight hydrocarbons ranging from light oil to methane. Yet another reaction occurring in the dissolver is the hydrogenation of the organic sulfur in the coal, thus producing hydrogen sulfide.

From the dissolver, the mixture passes to a separator where the gases are separated from the slurry of undissolved solids and coal solution. The raw gas is sent to a hydrogen recovery and gas desulfurization unit. The recovered hydrogen is then recycled and combined with the slurry coming from the slurry mix tank. Hydrocarbon cases are released and recovered, and the hydrogen sulfide is converted to elemental sulfur.

The slurry of undissolved solids and the coal solution is then separated in a filtration unit. In a commercial-scale process, the solids would be sent to a gasifier-converter where they would react with supplemental coal, steam, and oxygen to produce hydrogen for use in the process. The coal solution passes to the solvent recovery unit, and the product, solvent-refined coal, is produced. This material has a heating value of approximately 16,000 Btu/lb.

A modification to the process, SRC II, also called "slurry recycle", creates a final, liquid product and also leads to greater yields. The modification, which is still being tested, recycles a portion of the slurry to the front end of the plant so that it can be used to slurry fresh coal. More time in the reactor and higher hydrogen pressure help to increase the amount of liquid produced. Information on SRC II is limited because of its recent development.

15.2 PROCESS ADVANTAGES

SRC I:

- The process requires no catalyst and low amounts of hydrogen relative to most alternative processes;
- The solid product is low in sulfur (less than 1 percent) and ash (0.2 percent or less);
- The product has a high heating value (16,000 Btu/lb).

SRC II:

- Liquid fuel produced instead of a solid;
- Results in greater yields of the final product; Lowers the sulfur content of the fuel;
- Eliminates the solids separation step and further solids treatment.

15.3 PROCESS LIMITATIONS

SRC I:

- Operating costs for filtration are high;
- Handling methods for the solid product need further development.

SRC II:

- Hydrogen consumption is higher.

15.4 PROJECT HISTORY

The SRC project began in 1962 when Spencer Chemical Company was awarded a research contract by the OCR (now a part of ERDA) to study the technical feasibility of a coal de-ashing process, now called the SRC Process. In 1965, the process was successfully demonstrated in a 50-pound-per-hour continuous-flow unit, and the work on the contract was therefore completed. During the term of the contract, Gulf Oil Corporation acquired Spencer Chemical Company. After reorganization, the contract was assigned to the research department of PAMCO.

To develop the SRC Process further, a contract was awarded to PAMCO to design, construct, and operate a pilot plant that would be capable of processing 50 tons of coal per day. In 1968, Stearns-Roger Corporation completed the design for the pilot plant, but funds to begin construction were not available until late 1971. In June 1972, OCR extended its contract with PAMCO to construct and operate the pilot plant. Rust Engineering Company began constructing the pilot plant in July 1972 at Ft. Lewis, Washington, near Tacoma. As units were completed, preliminary tests of

process equipment and instrumentation were performed. The pilot plant became fully operational in October 1974.

Eleven material balance runs were made on the SRC pilot plant in the distillate solvent mode during 1975. Five successful runs were also made during 1975 in the slurry recycle mode. Overall, the 50 TPD pilot plant operated smoothly throughout 1975.

The laboratory unit was also run in both the distillate solvent and slurry recycle mode during 1975. The variables investigated included filtration rate, solvent recycling, slurry residence time, concentration of coal in the slurry, and temperature.

The pilot plant was modified in 1977 to incorporate SRC II. Operations with the modifications began in May 1977, with test runs on process variables in progress.

15.5 ENVIRONMENTAL CONSIDERATIONS

The environmental aspects of an SRC plant are similar to those encountered in power plants (coal dust, flue gases), coke plants (coal tar hydrocarbons), and petroleum refineries (solvents, tars, and residues).

No unique problems and no greater difficulty in meeting the environmental standards of these industries are anticipated for a commercial SRC plant. The effluents summary is presented in Figure 15-2.

Fugitive particulates (dust) and vapors can originate in several areas throughout the plant. Dust emissions are imminent when the coal is pulverized, the filter aid precoat slurry is prepared, or the mineral residue is dried and discharged. These emissions are controlled by using covered conveyors and induced draft vents with the vent gas being filtered to remove particulates. Coal is pulverized in a gas-swept grinding mill. As the coal is pulverized, it is dried by a hot, inert gas and carried into a bag house. Here the dried, powdered coal is collected for discharge into the slurry blend tank. This operation is in a closed system. The slurry is filtered. Diatomaceous earth, with or without asbestos, is used as a filter aid on the rotary filters.

In order to reduce vapors from the solvent tanks and other vessels, they are filled with inert gas. As the inert gas blanket is purged when a vessel is filled, the gas and vapors are discharged into an inert gas flow. This flow, as well as all of the other gases purged from the plant, goes into the flare piping system to be carried to the flare stack. All safety relief valves are also connected to the flare piping system. Flare burning is supplemented, if necessary, with natural gas.

Most of the sulfur liberated from the coal during processing appears as hydrogen sulfide in various gas streams. Hydrogen sulfide and carbon dioxide, the acid gases, are separated from the gas stream by an amine absorption unit. This concentrated hydrogen sulfide stream is converted to elemental sulfur as a by-product. In a commercial plant, a Claus sulfur plant would probably be used with an appropriate tail gas cleanup unit.

Liquid waste streams from the plant are combined and treated in a waste treatment plant by clarification, biological treatment, sand filtration, and carbon filtration. No unusual or unexpected problems have been encountered in the operation of this equipment.

The disposal of residue raises a primarily economic question. In a commercial plant, utilization of byproducts instead of disposal would make the process more economical. One method is to gasify the char. By an alternate method, a slagging gasifier would convert the residue into a relatively clean slag and synthesis gas (hydrogen and carbon monoxide). The sulfur in the residue would be converted into hydrogen sulfide which would appear in the synthesis gas and could be removed by usual acid gas removal methods.

A program has been developed for the application of instrumental neutron activation analysis to determine trace elements throughout the SRC plant.

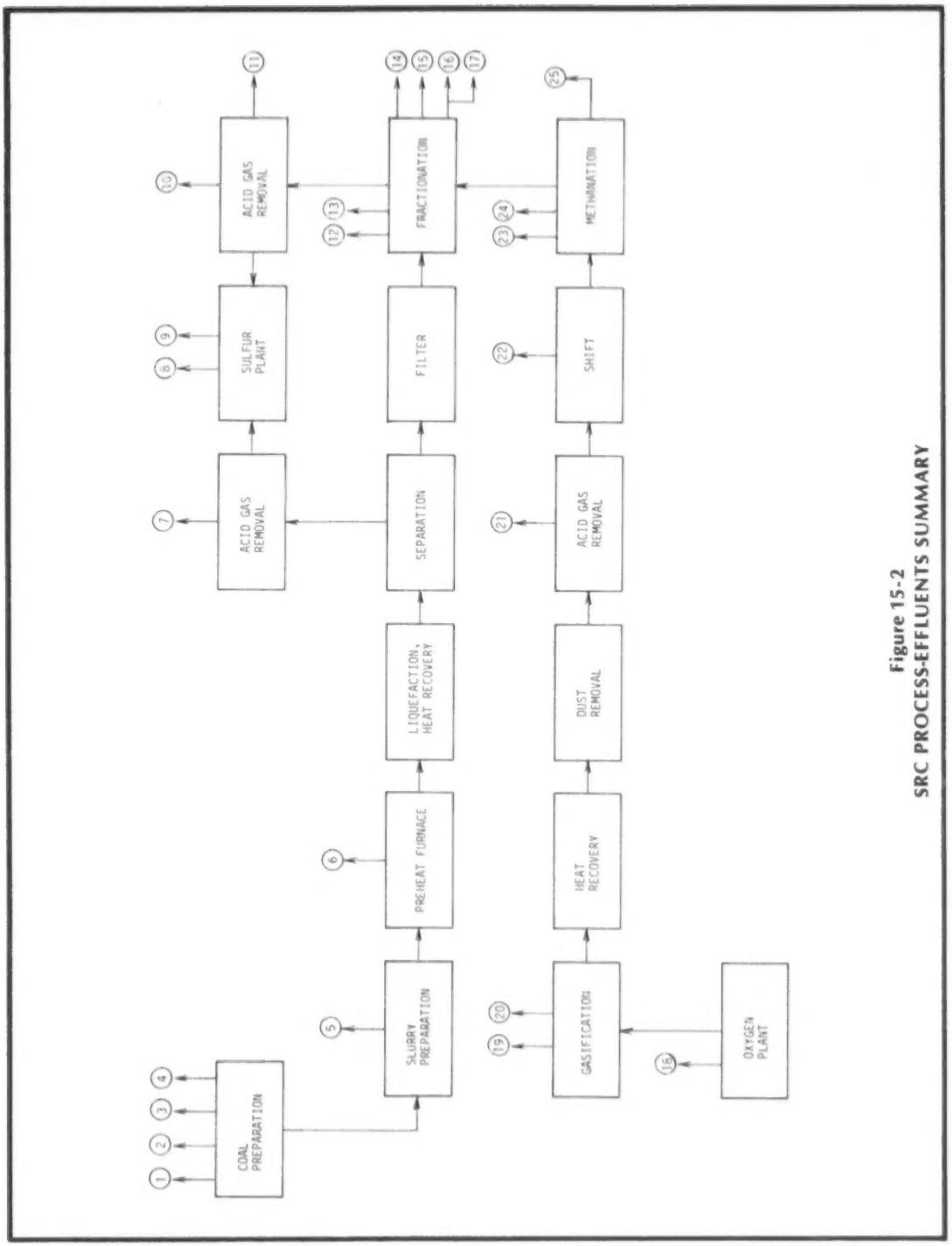

Figure 15-2
SRC PROCESS-EFFLUENTS SUMMARY

SRC PROCESS-EFFLUENTS SUMMARY FOR FIGURE 15-2

Stream #	Description
1	Gangue
2	Rain runoff
3	Dryer vent gas
4	Dust
5	Water vapor
6	Flue gas
7	Chemical purge
8	Sulfur product
9	Tail gas
10	Chemical purge
*11	Gas produced
12	Flue gas
13	Air from airfins
*14	Naphtha product
*15	Light fuel oil
*16	Heavy fuel oil
17	Heavy fuel oil to plant fuel
18	Nitrogen
19	Slag
20	Flue gas
21	Chemical purge
22	Flue gas
23	Carbon dioxide
24	Chemical purge
25	Condensate to waste water treatment

*Product, not an effluent

Auxiliary Facilities

A generalized discussion of auxiliary facilities common to most coal conversion plants is given in Appendix A.

Sulfur Balance

The SRC Process removes essentially all of the inorganic sulfur, 60 to 70 percent of the organic sulfur, and 98 percent of the ash in the coal. A typical sulfur balance is given in Table 15-1.

Table 15-1
SRC PROCESS SULFUR BALANCE

	percent
Liquid products	5.4
Byproducts sulfur	94.4
Tail gas	0.2
	100.0

APPENDICES

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Appendix A

AUXILIARY FACILITIES

In addition to the gasification and liquefaction systems, auxiliary facilities are needed to make by-product sulfur, supply oxygen, and generate steam and electricity. These facilities are common to all conversion plants even though they may differ in size and demand load and may use different fuels in the power generation area.

A.1 SULFUR PLANT

The most common type of sulfur recovery plant utilizes the Claus Process. With this process, acid gas entering the plant passes through a knock-out vessel to remove entrained liquids. Gas is then blown into the sulfur burner, where it is mixed with sufficient air to oxidize one-third of the hydrogen sulfide to sulfur dioxide. The combustion products enter the reaction furnace where enough residence time is provided for the Claus reactions to come to equilibrium. The sulfur produced is condensed. The remaining hydrogen sulfide is converted to sulfur through a 3-stage catalytic reactor.

Since the basic Claus reaction is limited by chemical equilibrium, the tail gas from the Claus unit will normally have sulfur values corresponding to 15,000 ppm of sulfur dioxide. These sulfur values are usually present in the form of hydrogen sulfide, sulfur dioxide, as well as unconverted carbonyl sulfide and carbon disulfide. A number of processes exist to clean up this stream. One of the more common ones is the SCOT^{R} Process or Shell-Claus Offgas Treatment System. In most instances, Claus offgas treatment systems will bring sulfur levels down to acceptable limits.

One other common process for sulfur recovery is the Stretford Process. This process removes hydrogen sulfide from gas streams and recovers the sulfur in elemental form. There are two variations of the Stretford Process based upon where the hydrogen cyanide is removed. In the first variation, the hydrogen cyanide is removed from the gas in a separate column before the removal of hydrogen sulfide. In the second variation, the hydrogen sulfide and hydrogen cyanide are removed in the same absorber. The first variation will be higher in capital cost but lower in operating cost, especially with respect to chemical usage. The processing scheme selected for a given application depends primarily on the concentration of hydrogen cyanide in the gas.

Operating pressures of Stretford plants vary from near atmospheric to 100 psig in the absorber. The solution oxidizer and sulfur recovery systems operate at atmospheric pressure. Feed gas temperatures are in the range of 80°F to 120°F.

Inlet hydrogen sulfide concentrations as low as 300 ppm and as high as 95 percent can be processed. The process can tolerate carbon dioxide in any amount and hydrogen cyanide concentrations as high as 2,000 ppm can be handled.

A.2 UTILITIES

Perhaps the major source of contaminants emitted to the air is the utilities system which includes steam generation, power generation, cooling water, treatment of make-up water and wastewater.

The choice of fuel for the generation of the power and steam required by the conversion plants markedly affects the overall process thermal efficiency and the effluents from the utilities system. It is generally less efficient, but much cleaner, to burn the clean product gas for this purpose. Coal-fired boilers would

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require flue gas desulfurization and additional solids handling. The effluents would be the same as those for current coal-fired installations. In the proposed WESCO gasification plant, an air blown gasifier was included to make fuel gas for the utilities system. This area, as mentioned earlier, does emit the largest amount of pollutants but they can be easily contained with current technologies.

A.3 COOLING WATER

The largest effluent to the air is from the utility cooling tower. Flow of air through the tower may be as high as 85,000 MMSCFD. In addition, there is a drift loss due to mist carried out by the air. A typical estimate of this would be 263,000 lb/hr, although it could be reduced considerably by using some of the new techniques developed to control drift loss from cooling towers. Drift can cause deposits in the nearby area due to dissolved solids in the cooling water. Consideration should also be given to the potential fog problem or plume associated with cooling towers due to condensation under unfavorable atmospheric conditions. These adverse environmental impacts may be reduced by the use of a commercial design which maximizes air-cooled heat exchanges reserving the use of water for trim cooling.

A.4 WASTEWATER TREATMENT

Water streams that are directed to the water-treating facilities will contain traces of ammonia, phenols, and hydrocarbons. There will be evaporation and the possibility of odors from retention ponds and water treatment facilities. Control of emissions in wastewater streams is a well developed art in the petroleum refining industry so that no new technologies will need to be developed. Each treatment system will be site specific.

Appendix B

COAL STORAGE AND PREPARATION

Common to all coal conversion processes are the operations of coal cleaning, grinding, and storage. In some instances, a drying step is also included.

On-site storage will be required for all plants to provide backup for continuous conversion operations. For a commercial sized plant, thirty days' worth of storage would require four piles, each about 200 feet wide, 20 feet high, and 1,000 feet long. Containment of airborne dusts is generally the only air pollution control required for transport and storage operations although odor may be a problem in some instances. A covered or enclosed conveyance system with dust removal equipment (baghouses) may be necessary. Careful management and planning will minimize dusting and wind loss and the hazard of combustion in storage facilities.

Liquid discharges from coal storage piles will result from rain or other forms of precipitation. The runoff from the 20 to 25 acre area during a rainstorm could be as large as 5,000 gpm. Such runoff would be acidic in nature and contain a large amount of particulate matter. Accordingly, this runoff must be contained and treated to prevent a major pollution problem. If properly designed, this water, after treatment, may be of sufficient purity to be used in the plant's water system.

Coal-grinding operations associated with the preparation operations create large amounts of dust. During processing, air is aspirated into the ball mill grinding operation. The air stream is heated in a circulation system and passed through the mills, where it serves both to control moisture in the pulverizing process and transport medium for the pulverized material. The coal/air mixture passes through cyclones where coal separation occurs, and the air stream is discharged into the atmosphere through bag filters. This arrangement is commercially proven, with acceptable particulate emissions, even though the load on the filters for a commercial plant could amount to 60 TPD. Only trace quantities of hydrocarbons have been detected in such commercial streams, and odor is not considered a problem. Collected fines from the filters are recycled to the mill product. There should be no solid effluent from the coal-grinding plant.

Coal drying may be required in some instances, especially when western coal is involved. The moisture content of western bituminous coals averages 18 to 20 percent and lignite may contain as much as 30 percent moisture. The majority of the coal drying processes involve entraining sized coal in a hot gas stream. This gas stream may be generated through the burning of natural gas, coal or using hot process gas generated during the gasifying operation. Where coal is burned as a heat source or hot process gas is used, various sulfur, nitrogen, and organic compounds are introduced into the dryer stack which require removal or reduction in concentration in order to meet EPA emission standards. To this end, pilot plants have tested the use of limestone or other suitable acceptors for reduction of sulfur compounds. Depending on the size of the drying operation, varying amounts of spent acceptor will require disposal. In addition, if coal is burned, coal ash will represent a solid waste which will require handling. As with any combustion process, chemical waste will require handling. Likewise, with combustion processes, chemical compounds will be released to the atmosphere in varying amounts and must be considered in the overall emission picture.

In addition to the preceeding processes, other operations may be part of the plant environment and may include coal mining, laundering, and screening. These processes have been studied very thoroughly and can be predicted for any mine capacity. With proper design and maintenance, coal preparation areas of coal conversion plants will not create any effluent problems.

APPENDIX C
SUMMARY OF COAL CONVERSION PROCESSES

PROCESS	DEVELOPER/LICENSOR	U.S. PLANT LOCATIONS(S)	COALS ACCEPTED	COAL PREPARATION
GASIFICATION				
BI-Gas	Bituminous Coal Research, Inc.	Homer City, PA	All	Sizing
CO_2Acceptor	Conoco Coal Development Co.	Rapid City, SD	Lignite	Sizing, Drying
Coalcon	Union Carbide	New Athens, IL (Proposed)	Mildly Caking	Sizing, Devolatilization
HYGAS	Institute of Gas Technology	Chicago, IL	Mildly Caking	Sizing, Mild Oxidation
Koppers-Totzek	Koppers Company Inc.	Cedar Bayou, TX (Proposed)	All	Sizing
Lurgi	Lurgi Mineraloltechnik	None	Mildly Caking	Sizing, Drying
Slagging Lurgi	Conoco	Noble County, OH	Mildly Caking	Sizing
Synthane	U.S. Bureau of Mines	Bruceton, PA	All	Sizing, Mild Oxidation
Wellman-Galusha	McDowell Wellman Engineering Co.	Several locations around U.S.	All	Sizing
Winkler	Davy Powergas, Inc.	None	Mildly Caking	Sizing, Drying
LIQUEFACTION				
COED (Char Oil Energy Development)	FMC Corporation	Perry County, IL	All	Sizing, Drying
Donor Solvent	Exxon Research & Development Co.	Baytown, TX	All	Sizing, Drying, Slurrying
H-Coal	Hydrocarbon Research, Inc. (HRI)	Catlettsburg, KY	All	Sizing, Drying, Slurrying
SRC (Solvent Refined Coal)	Pittsburg & Midway Coal Mining Co.	Ft. Lewis, WA and Wilsonville, AL	All	Sizing, Drying, Slurrying
INDRECT LIQUEFACTION				
Fischer-Tropsch	Lurgi Mineraloltechnik	None	Not Applicable	Coal Gasification

SUMMARY OF COAL CONVERSION PROCESSES

REACTOR TYPE	REACTANTS	OPERATING CONDITIONS (TEMPERATURE, PRESSURE)	HEAT SOURCE	PRIMARY PRODUCTS
Entrained Flow	Steam, Oxygen	2500°-3000°F, 1000 psig	Char Combustion in Second Stage	High-Btu Gas
Fluidized Bed	Steam, Air, Dolomite	1500°F, 150 psig	Circulating Stream of Hot Dolomite	High-Btu Gas
Fluidized Bed	Hydrogen, Oxygen	1040°F, 500 psig	Circulating Stream of Hot Ash	High-Btu Gas
Fluidized Bed	Steam, Hydrogen, Oxygen, Air	1250°F, 1100 psig	Char Combustion in Separate Stage	High-Btu Gas
Entrained Flow	Steam, Oxygen	2750°F, 0 psig	Partial Combustion	Medium-Btu Gas (but upgraded to hydrogen in this case)
Fixed Bed	Steam, Oxygen or Air	1100°F, 400 psig	Partial Combustion	High-Btu Gas
Fixed Bed	Steam, Oxygen	2800°F, 80-400 psig	Partial Combustion	High-Btu Gas
Fluidized Bed	Steam, Oxygen	1800°F, 1000 psig	Partial Combustion	High-Btu Gas
Fixed Bed	Steam, Oxygen or Air	1350°F, 0 psig	Partial Combustion	Low-Btu Gas
Fluidized Bed	Steam, Oxygen or Air	1850°F, 0 psig	Partial Combustion	Medium-Btu Gas or Low-Btu Gas
Multi-Stage Fluidized Bed	Steam, Hydrogen, Oxygen	Stage 1: 600°F, 20 psig Stage 2: 850°F, 20 psig Stage 3: 1000°F, 20 psig Stage 4: 1600°F, 20 psig	Char Combustion in Separate Stage	Liquid Syncrude
Tubular	Hydrogen, Solvent	800°F, 2000 psig	External Process Heater	Liquid Syncrude
Ebullated Bed	Hydrogen, Solvent	850°F, 3000 psig	External Process Heater	Boiler Fuel or Liquid Syncrude
Dissolver	Hydrogen, Solvent	850°F, 1500 psig	External Process Heater	Low-Ash Low-Sulfur Solid Fuel (SRC)
Fixed Bed Fluidized Bed	Synthesis Gas	Fixed Bed - 450°F, 360 psig (Arge); Fluidized Bed - 620°F, 330 psig (Kellogg)	Not Applicable	Gasoline, LPG, Oils, Waxes, Alcohols, Medium-Btu Gas

PROCESS STATUS	DIFFERENCES/COMMENTS	PROCESS
		GASIFICATION
Pilot Facility 120 T/D	There are problems with slag removal from the gasifier. The process may be technically feasible if this is achieved. Phillips Petroleum is responsible for the pilot facility.	BI-GAS
Pilot Facility 40 T/D	Conoco's project manager for this process stated at the 9th Synthetic Pipeline Gas Symposium that this process is technically feasible, but the economics relative to the proved Lurgi process may not be significantly better, thus raising the question as to whether the CO_2 Acceptor process will be commercialized.	CO_2 Acceptor
Dormant	The Coalcon process can not handle caking coal and is still under development by Union Carbide.	Coalcon
Pilot Facility 1970 15 MM SCFD	This is a high-pressure, high-Btu system which uses a four-stage gasifier. Design is underway for a demonstration facility by Procon, but there are no plans for construction.	HYGAS
Commercial Worldwide	Air Products & Chemicals has proposed the Koppers-Totzek process to be used to produce hydrogen on a commercial basis at Cedar Bayou, TX.	Koppers-Totzek
Commercial Worldwide	There are no Lurgi gasifiers presently operating in the U.S. The Lurgi Process has been in commercial use since 1936.	Lurgi
Demonstration Facility 1981 59 MM SCFD	Conoco was awarded a contract for the design phase of the Slagging Lurgi project at Noble County, OH during 1977.	Slagging Lurgi
Pilot Facility 1977 1.4 MM SCFD	Problems with the pilot facility include the formation of large diameter clinkers (ash agglomerates) in the gasifiers.	Synthane
Commercial Facility 1981 1 MM SCFD	This process has been in commercial use for 35 years. Three commercial facilities are due to be on stream in 1981. All three have the same capacity. Wellman-Galusha is a single-stage gasifier.	Wellman-Galusha
Commercial Worldwide	Winkler operates at low pressure and produces fuel gas or industrial synthesis gas.	Winkler
		LIQUEFACTION
Pilot Facility 1974 21,000 T/Y	This process produced large amounts of low-value char so the COGAS gasification process was developed to use char as a feedstock. COED is essentially a pyrolysis process in which liquid products are distilled from coal by the application of heat to a solvent-free fluidized bed.	COED (Char Oil Energy Development)
Pilot Facility 1980 250 T/D	Exxon's Donor Solvent utilizes catalytic hydrogenation of the donor solvent in a separate step and no catalyst in the coal extraction (hydrogenation) step.	Donor Solvent
Pilot Facility 1978 600 T/D	H-Coal uses a catalyst in the coal extraction step with no separate solvent hydrogenation step.	H-Coal
Pilot Facility 1976 50 T/D (Process Development Unit, 1976, 6 T/D)	SRC uses no catalyst in the hydrogenation step.	SRC (Solvent Refined Coal)
		INDIRECT LIQUEFACTION
Commercial Worldwide - especially South Africa	This is an indirect liquefaction process. It is a unique system which is used after gasification to produce hydrocarbon products from carbon monoxide and hydrogen.	Fischer-Tropsch

Appendix D

LIST OF ABBREVIATIONS

AG ..... Aktiengeselschaft - A joint stock company under German law; corporation
atm ..... atmosphere(s)

BPD ..... Barrels per day
Btu ..... British thermal unit
Btu/hr ..... British thermal units per hour
Btu/lb ..... British thermal units per pound
Btu/SCF ..... British thermal units per standard cubic foot

COED ..... Char-Oil Energy Development
CTD ..... control technology development

EA ..... environmental assessment
EIS ..... environmental impact statement
EPA ..... Environmental Protection Agency
ERDA ..... Energy Research and Development Administration

ft/sec ..... feet per second

GmbH ..... Gesellschaft mit beschränkter Haftung - A closed corporation under German law; Ltd.

gpm ..... gallons per minute

lb/cu ft ..... pounds per cubic foot
lb/hr ..... pounds per hour
lb/MM Btu .. pounds per million British thermal units
lbs ..... pounds
LP ..... liquid propane
LPG ..... liquefied petroleum gas

MM ..... million
MMSCFD ... million standard cubic feet per day
MW ..... megawatt

OCR ..... Office of Coal Research; now part of ERDA

ppm ..... parts per million
psi ..... pounds per square inch
psig ..... pounds per square inch gauge

SNG ..... substitute natural gas
SRC ..... Solvent Refined Coal

TPD ..... tons per day
TPH ..... tons per hour
TPY ..... tons per year

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Appendix E

CONVERSION FACTORS

To Convert From:	To:	Multiply by:
Btu/hour	watt (W)	2.93077 E-01
Btu	joule (J)	1.055056 E + 03
calorie	joule (J)	4.19002 E + 00
centimeter of Hg	pascal (Pa)	1.33322 E + 03
centipoise	pascal (Pa · s)	1.000 E − 03
degree centigrade	degree kelvin (k)	$t_k = t_c + 273.15$
degree Fahrenheit	degree celsius	$t_c = (t_f - 32)/1.8$
foot	meter(m)	3.048 E − 01
ft^3/sec	$meter^3$/sec	2.831685 E − 02
gallon/min	$meter^3$/sec	6.309020 E − 05
inch	meter (m)	2.54 E − 02
kWh	joule (J)	3.6 E + 06
month	seconds (s)	2.628 E + 06
lb/in^2	$kilogram/meter^2$	2.926397 E − 04
lb/in^3	$kilogram/meter^3$	2.76799 E + 04
psi	pascal (Pa)	6.894757 E + 03
ton (assay)	kilogram (kg)	2.916667 E − 02
tonne	kilogram (kg)	1.0000 E + 03
year (calendar)	seconds(s)	3.1536 E + 07

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Appendix F

GENERAL REFERENCES

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Appendix G

EPA REPORTS ON SYNTHETIC FUELS FROM COAL

The following reports were published before October 1976.

EPA No.*	NTIS No.**	Title and Date
EPA-600/2-76-177b	PB 260-475/AS	"Fuel Contaminants: Volume 2. Removal Technology Evaluation," Battelle Columbus Labs (September 1976)
EPA-600/2-76-259	PB 261-916/AS	"Initial Environmental Test Plant for Source Assessment of Coal Gasification," Institute of Gas Technology (September 1976)
EPA-600/2-76-177a	PB 256-020/AS	"Fuel Contaminants: Volume 1. Chemistry," Battelle Columbus Labs (July 1976)
EPA-600/2-76-149	PB 257-182/AS	"Symposium Proceedings: Environmental Aspects of Fuel Conversion Technology, II (December 1975, Hollywood, Florida)," Research Triangle Park (June 1976)
EPA-600/2-76-153	PB 257-134/AS	"Fuel Gas Environmental Impact," United Technologies Research Center (June 1976)
EPA-600/2-76-102	PB 253-946/AS	"Environmental Aspects of Retrofitting Two Industries to Low and Intermediate Energy Gas from Coal," Battelle Columbus Labs (April 1976)
EPA-600/2-76-101	PB 255-842/AS	"Evaluation of Pollution Control in Fossil Fuel Conversion Processes: Final Report," Exxon Research and Engineering (April 1976)
EPA-600/2-75-078	PB 249-454/AS	"Fuel Gas Environmental Impact: Phase Report," United Technologies Research Center (November 1975)
EPA-650/2-74-009m	PB 249-847/AS	"Evaluation of Pollution Control in Fossil Fuel Conversion Processes - Liquefaction: Section 3. H-Coal Process," Exxon Research and Engineering (October 1975)

* Available through U.S. EPA, National Environment Research Center, Research Triangle Park, North Carolina 27711, (919) 549-8411.

** Available through the National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Road, Springfield, Virginia 22151, (703) 321-8654.

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EPA No.	NTIS No.	Title and Date
EPA-650/2-74-009l	PB 249-845/AS	"Evaluation of Pollution Control in Fossil Fuel Conversion Processes - Analytical Test Plan," Exxon Research and Engineering (October 1975)
EPA-650/2-74-009k	PB 246-311/AS	"Evaluation of Pollution Control in Fossil Fuel Conversion Processes - Coal Treatment: Section 1. Meyers Process," Exxon Research and Engineering (September 1975)
EPA-650/2-74-009j	PB 249-846/AS	"Evaluation of Pollution Control in Fossil Fuel Conversion Processes - Gasification: Section 8. Winkler Process," Exxon Research and Engineering (September 1975)
EPA-650/2-74-009i	PB 247-226/AS	"Evaluation of Pollution Control in Fossil Fuel Conversion Processes - Gasification: Section 7. U-Gas Process," Exxon Research and Engineering (September 1975)
EPA-650/2-74-009h	PB 247-225/AS	"Evaluation of Pollution Control in Fossil Fuel Conversion Processes - Gasification: Section 6. Hygas Process," Exxon Research and Engineering (August 1975)
EPA-650/2-74-009g	PB 243-694/AS	"Evaluation of Pollution Control in Fossil Fuel Conversion Processes-Gasification: Section 5. Bi-Gas Process," Exxon Research and Engineering (March 1975)
EPA-650/2-74-009f	PB 241-792/AS	"Evaluation of Pollution Control in Fossil Fuel Conversion Processes - Liquefaction: Section 2: SRC Process," Exxon Research and Engineering (March 1975)
EPA-650/2-74-009e	PB 240-371/AS	"Evaluation of Pollution Control in Fossil Fuel Conversion Processes - Liquefaction: Section 1: COED Process," Exxon Research and Engineering (January 1975)
EPA-650/2-74-009d	PB 241-141/AS	"Evaluation of Pollution Control in Fossil Fuel Conversion Processes - Gasification: Section 1, CO_2 Acceptor Process," Exxon Research and Engineering (December 1974)
EPA-650/2-74-009c	PB 237-694/AS	"Evaluation of Pollution Control in Fossil Fuel Conversion Processes - Gasification: Section 1: Lurgi Process," Exxon Research and Engineering (July 1974)
EPA-650/2-74-009b	PB 237-113/AS	"Evaluation of Pollution Control in Fossil Fuel Conversion Processes - Gasification: Section 1: Synthane Process," Esso Research and Engineering (June 1974)
EPA-650/2-74-118	PB 238-304/AS	"Symposium Proceedings: Environmental Aspects of Fuel Conversion Technology," Research Triangle Park (May 1974)

EPA No.	NTIS No.	Title and Date
EPA-650/2-74-052	PB 237-116/AS	"Study of Potential Problems and Optimum Opportunities in Retrofitting Industrial Processes to Low and Intermediate Energy Gas from Coal," Battelle Columbus Labs (May 1974)
EPA-650/2-74-009a	PB 231-675/AS	"Evaluation of Pollution Control in Fossil Fuel Conversion Processes - Gasification: Section 1. Koppers-Totzek Process," Esso Research and Engineering (January 1974)
EPA-R2-73-249	PB 225-039/AS	"Potential Pollutants in Fossil Fuels," Esso Research and Engineering (June 1973)

Appendix H

GLOSSARY

Acceptor - Calcined carbonate that absorbs carbon dioxide evolved during gasification, liberating heat.

Acid gas - The hydrogen sulfide and carbon dioxide found in a gas stream.

Agglomerates - Assemblages of ash particles rigidly joined together, as by partial fusion (sintering).

Annulus - The void space between two concentric pipes of different diameter.

Ash - Solid residue remaining after the combustion of coal.

Bench-scale testing - Testing of materials, methods, or processes on a small scale such as on a laboratory worktable.

Benfield Process - The Benfield hot potassium carbonate process was developed at the U.S. Bureau of Mines, Bruceton, Pennsylvania, in the early 1950's. Their work has since been widely used for scrubbing of CO_2 and H_2S from industrial gases at moderate to high temperatures.

Calcine - To heat to a high temperature without fusing; to heat ores, precipitates, concentrates or residues so that hydrates, carbonates, or other compounds are decomposed and volatile matter is expelled.

Catalytic cracking - The partial decomposition of high molecular weight organic compounds into lower molecular weight compounds, as the result of catalytic reaction.

Char - To reduce to charcoal or carbon by exposure to heat; coke made by the low-temperature carbonization of lignite.

Claus Process - Industrial method of obtaining elemental sulfur through the partial oxidation of gaseous hydrogen sulfide in the air followed by catalytic conversion to molten sulfur.

Coke - Strong porous residue consisting of carbon and mineral ash formed when bituminous coal is heated in a limited air supply or in the absence of air. Coke may also be formed by thermal decomposition of petroleum residues.

Condenser - A heat-transfer device that reduces a thermodynamic fluid from its vapor phase to its liquid phase.

Cresols - A combination of isomers, derived from coal tar; a yellowish liquid with a phenolic odor; used as a disinfectant; used in the manufacture of resins, and flotation of ore.

Cyclone - Essentially a settling chamber to separate solid particles from a gas, in which gravitational acceleration is replaced by centrifugal acceleration.

Diatomaceous earth - A yellow, white, or light gray, siliceous, porous deposit made of the opaline shells of diatoms; used as a filter aid, absorbent, and thermal insulator.

Dowtherm - A trade name for any of several eutectic mixtures of diphenyl oxide and diphenyl; used in liquid and vapor form as a heat-transfer fluid.

Ebullated-bed - Gas, containing a relatively small proportion of suspended solids, bubbles through a higher density fluidized phase with the result that the system takes on the appearance of a boiling liquid.

Effluent - A liquid, gas, or solid waste that has passed through a processing operation.

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Feed - Process or act of supplying material to a processing unit for treatment; the material supplied to a processing unit for treatment.

Fixed-bed - A process in which the additive material (catalyst, absorbent, filter media) remains stationary in the chemical reactor.

Fluidized-bed (Fluid-bed) - Assemblage of small solid particles maintained in balanced suspension against gravity by the upward motion of a gas.

Gasifier - Apparatus which converts coal to gaseous fuel.

Hopper - A funnel-shaped receptacle with an opening at the top for loading and a discharge opening at the bottom for bulk-delivering material such as coal.

Hydroclone - A cone shaped liquid-cleaning apparatus operated by centrifugal separation that is used for separating solid particles from a liquid.

Mercaptans - A descriptive name for most organic compounds containing the sulfhydryl group.

Moving-bed - A process whereby granulated solids are circulated (moved) either mechanically or by gravity flow. Used in catalytic and absorption processes.

Naphthalene - White, volatile crystals with coal tar aroma; insoluble in water, soluble in organic solvents; used for fungicides, lubricants, and resins, and as a solvent.

pH - A measurement of the acidic or basic character of a substance.

Phenols - Aromatic ring compounds which possess one or more hydroxyl radicals as the primary group.

Preheater - A device for preliminary heating of a process stream that will undergo further use or treatment.

Pulverization - Breaking up or grinding into small fragments.

Purisol Process - Developed by Lurgi Mineraloetechnik GmbH in West Germany for removal of acid gases from natural gas, hydrogen and synthesis gas by physical absorption in N-Methyl-2-Pyrrolidone (NMP or M-Pyrol). The process is used for reduction of high CO_2 concentrations, bulk removal of acidic components, and selective H_2S removal.

Pyridine - Organic base; flammable, toxic yellowish liquid, with penetrating aroma and burning taste; used as a solvent.

Pyrolysis - The breaking apart of complex molecules into simpler units by the use of heat.

Quinoline - Water-soluble, aromatic nitrogen compound; colorless, hygroscopic liquid; used as a chemical intermediate.

Raw gas - Gas which has not been purified.

Reactor - Device or process vessel in which chemical reactions take place during a chemical conversion type of process.

Rectisol Process - Developed and licensed by American Lurgi Corporation. The process utilizes methanol for removal of acid gases by physical absorption at relatively low temperatures. The process is used for removal of H_2S, CO_2, HCN, NH_3, gum-forming hydrocarbons, and other impurities from coal or oil gasification processes that produce fuel gas, synthesis gas or methanol.

Refractories - Materials of very high melting points with properties that make them suitable for such uses as furnace linings.

Regenerator - Device or system designed to restore a chemical to its original level of activity.

Residue - The product remaining after separation.

Selexol Solvent Process - Developed by Allied Chemical Corporation in the early 1960's.* The process utilizes dimethyl ether of polyethylene glycol to remove H_2S, CO_2, and other acidic and non-acidic components from industrial gases by physical absorption. Applications include sour natural gas, synthesis gas, and refinery gases.

Slag - Molten coal ash composed primarily of silica, alumina, iron oxides, and calcium and magnesium oxides.

Slurry - A suspension of pulverized solid in a liquid.

Stream - A body of flowing liquid or gas carrying various input or discharge materials to and from the process apparatus.

Stretford Process - Originally developed by the North Western Gas Board of the British Gas Corporation, this process primarily removes hydrogen sulfide from gas streams by chemical absorption. Elemental sulfur is produced by the process.

Sweet crude - Crude petroleum oil containing little sulfur.

Syncrude - Synthetic crude - Oil produced by the processing of coal, coal extracts, oil sands, or oil shale.

Tail gas - A gas issuing from a gas-treatment unit which may be recycled to the process or exhausted.

Tuyere - An opening in the shell and refractory lining of a furnace through which air is forced.

Xylenols - Highly toxic, combustible crystals; slightly soluble in water, soluble in most organic solvents; used as a chemical intermediate, disinfectant, solvent and fungicide.